**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE**

IN THE MATTER OF INTEGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SERVICE BY DELMARVA POWER & LIGHT COMPANY UNDER 26 DEL C. § 1007(c) & (d): REVIEW AND APPROVAL OF THE REQUEST FOR PROPOSALS FOR THE CONSTRUCTION OF NEW GENERATION RESOURCES UNDER 26 DEL. C. § 1007(d)
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PSC DOCKET NO. 06-241

FINAL REPORT REGARDING DELMARVA POWER & LIGHT COMPANY'S PROPOSED RFP

PREPARED FOR:

Delaware Public Service Commission
Delaware Office of Management and Budget
Delaware Energy Office
Delaware Controller General

ADOPTED BY:

Delaware Public Service Commission Staff
Delaware Energy Office

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I Introduction

On August 1, 2006, Delmarva Power & Light Company ("Delmarva" or "DP&L") filed a proposed Request for Proposals ("Proposed RFP") for the purchase of power under long-term contracts from new generation resources to be built within the State of Delaware for the purpose of supplying standard offer service, as required under the Electric Utility Retail Customer Supply Act of 2006 (the "Act").[1] As directed by the Act,[2] the Delaware Public Service Commission ("Commission"), the Energy Office (an office of the Department of Natural Resources and Environmental Control), the Office of Management and Budget, and the Controller General ("State Agencies") have retained an independent consultant ("Independent Consultant") with expertise in the area of energy procurement to oversee the development of the Request for Proposals ("RFP") and to assist the State Agencies in evaluating the bids submitted pursuant to the RFP. This Final Report contains the analysis and recommendations of the Independent Consultant—New Energy Opportunities, Inc. and its consulting team of Merrimack Energy Group, Inc., La Capra Associates, Inc. and Edward L. Selgrade, Esq.—with respect to the Proposed RFP. Our experience and capabilities in the field of power procurement are set forth in Appendix A. This report is submitted in Docket No. 06-241, the proceeding initiated by the Commission to carry out the long-term power procurement process required under the Act. This report follows the Initial Report submitted by the Independent Consultant on September 18, 2006, a markup to Delmarva's Proposed RFP submitted on September 27, 2006 and takes into consideration initial and reply comments submitted by participants in this proceeding as well as comments made at a workshop on August 18, 2006.

Following Delmarva's filing of the Proposed RFP, the Commission convened a workshop at which Delmarva presented an overview of the Proposed RFP and various participants in this proceeding and members of the public had an opportunity to ask questions and to express their views. After the workshop, the following participants submitted comments and/or reply comments: Acacia Consulting, Bluewater Wind, LLC ("Bluewater Wind"), Coalition for Climate Change Study and Action, Delaware Energy Office, Delaware Energy Users Group, Delaware Nature Society, Department of Public Advocate, Green Delaware, NRG Energy, Inc. ("NRG"), SCS Energy, LLC ("SCS Energy"), Jeremy Firestone and Willet Kempton of the College of Earth and Marine Studies of the University of Delaware ("Firestone and Kempton"), the Natural Resources Defense Council and various members of the public.[3]

This report addresses a variety of matters that are important to a successful conduct of a RFP procurement process for new generation that would be consistent with the requirements of the Act. In Part II of this report, we address the relationship between the RFP process and the Integrated Resource Planning ("IRP") process mandated by the Act for standard offer service ("SOS"). In addition, we address the relationship between the role of Delmarva, and its consultants, and the Delaware Agencies and their consultant in the design of the RFP and the evaluation of bids submitted in response to the RFP. In Part III we address what we believe to be

[1] 26 Del C. § 1007(d).
[2] 26 Del C. § 1007(d)(2).
[3] See http://www.state.de.us/delpsc/irp.shtml.

the proper criteria to be used in our evaluation of the Proposed RFP design, and for making recommendations for modifications, consistent with Legislative objectives. Turning to the RFP design issues themselves, we address the product to be purchased and related issues in Part IV, including maximum and minimum contract size and the nature of the energy sale obligation, threshold requirements in Part V, bid evaluation methodology in Part VI, including price and non-price evaluation factors, Delmarva's proposed required contractual terms and conditions in Part VII, and provide brief conclusions in Part VIII.

II The Relationship between the RFP and IRP Process and between Delmarva and the State Agencies

In the face of sharply increasing rates for residential and small commercial Delmarva SOS customers to be effective on May 1, 2006, the Delaware Legislature approved a phased-in rate increase and instituted various rules and requirements applicable to future Standard Offer Service. Under the Act, Delmarva is required to conduct Integrated Resource Planning in its capacity as the SOS supplier for its customers,[4] and "[a]s part of the initial IRP process," Delmarva was required to file a proposed RFP for long-term procurement of power from new electric generation to be built in Delaware "to immediately attempt to stabilize the long-term outlook for Standard Offer Supply in the DP&L service territory."[5] The Act is not explicit regarding how the RFP process relates to the IRP process, but the thrust of the Act is clear that the RFP process is to be expedited.

On December 1, 2006, December 1, 2008, and each 2-year anniversary thereof, Delmarva is required to file with the Delaware Agencies an Integrated Resource Plan to systemically evaluate all available supply options during a ten-year planning period in order to cost-effectively acquire sufficient and reliable resources to meet its customers' needs. As part of the first IRP process, Delmarva was required to file a proposed RFP (August 1, 2006) *before* it files its IRP (December 1, 2006), with the issuance of the RFP to take place after approval by the Commission and Energy Office, with such modifications as these agencies may direct (November 1, 2006). The Act requires that bids be due no later than December 22, 2006 (after the IRP filing), and that the State Agencies, with the assistance of the Independent Consultant, shall evaluate the proposals and may determine to approve one or more proposals in response to the RFP on or before February 28, 2007. Once contract terms are finalized, the State Agencies may direct Delmarva to enter into one or more contracts, and "Delmarva shall enter into such contract(s)."

In the Proposed RFP, Delmarva describes the bid evaluation and selection process as follows:

> Delmarva shall determine whether [the proposals submitted] meet all threshold requirements, and among those proposals, shall select the highest rated one(s) for evaluation under Delmarva's Integrated Resource Plan (IRP).[6]

[4] 26 Del C. § 1007(c)(1).
[5] 26 Del C. § 1007(d). The full text of the section of the Act that addresses the RFP process is set forth in Appendix B of this report.
[6] Section 1, p. 1.

> The proposal evaluation process will culminate in the selection of an approved bidder(s), subject to the results of the Company's IRP to be filed with the Commission on or before December 1, 2006. The IRP process will evaluate available supply and demand-side options during a ten (10)-year planning period in order to provide efficient and reliable resources required over time to meet its customers' needs at a reasonable cost. The IRP will be amended after its filing date with the results from the RFP. If the winning proposal(s) results in a more cost-effective IRP, Delmarva will then negotiate with bidder(s) to execute a PPA [power purchase agreement].[7]

Delmarva states that if it selects a winning bidder(s) in the RFP process, it will inform the State Agencies of the Company's selection(s). Further, the "agencies are expected to make their decision by February 27, 2007. If the public agencies approve, Delmarva will receive authority to sign a PPA with that bidder(s), subject to the results of the IRP process and a final Delmarva decision."

Several participants in this proceeding have expressed concern that tying the RFP process to the IRP could result in considerable uncertainty and a potentially lengthy and unwarranted delay.[8] We believe that such a result—lengthy delay and uncertainty—would not be consistent with the Legislative intent and can be avoided. The evaluation methodology used in the RFP process should be consistent with that used in the IRP process, at least with respect to the economic analysis. Hence, a proposal that is evaluated as being cost-effective under the RFP process should rank highly in the IRP analysis. While the Legislative criteria for the RFP process may be somewhat different from those applicable more generally to the IRP process (a matter we address in the next section), the commonality of the analytical tools and fundamental economic criteria used should allow for an expeditious review by the Commission of the results of the RFP evaluation, as well as any supplemental ranking in the context of the IRP process.

Accordingly, we believe that there is a reasonable likelihood that the State Agencies would have sufficient information from the RFP evaluation, as well as any input from the IRP process, to make a decision by February 28, 2007 regarding proposals in the RFP process. If the Commission and the State Agencies need more time to make a decision, taking into consideration the impact on the IRP, we recommend that they set forth a schedule to make a final decision within a period not to exceed another two months or so in order that bidders can be assured that a decision will be made with respect to RFP proposals for new generation in Delaware in a timely fashion. The Commission and the Energy Office should make it clear that sufficient information from both the RFP and IRP process should be submitted before them in a timely fashion to enable them to make a decision by February 28, 2007. Finally, until a final decision is made, high ranking bids in the RFP process (including those that are not the highest ranking) should not be rejected.

We do have concerns about the way the Proposed RFP characterizes Delmarva's role in the bid evaluation process in relation to the role of the State Agencies and their Independent Consultant. Under the Act, the State Agencies are responsible for evaluating the proposals, with the

[7] Section 2.1, p. 5.
[8] See, e.g., Comments of Bluewater Wind at 14-15.

assistance of the Independent Consultant, and for deciding whether contracts resulting from such proposals should be approved. At the workshop, the Commission Staff has set forth a tentative schedule for the bid evaluation phase of the RFP process:

- December 22, 2006—Proposals due
- February 9, 2007—State Agencies' evaluation of proposals filed
- February 21, 2007—Written public comments filed
- February 23, 2007—Final Stage Agencies' evaluation filed
- February 27, 2007—Commission meeting to consider bid evaluation[9]

This process focuses on the State Agencies' evaluation of proposals, with the assistance of the Independent Consultant, and does not address Delmarva's role in the evaluation and selection process. Delmarva's Proposed RFP speaks only of its role in evaluation and selection and only provides a review role for the State Agencies after Delmarva and its consultant, ICF International (ICF), have made decisions on proposals. It makes no reference to the Independent Consultant retained to assist the State Agencies.

We believe that the RFP process will be best carried out if both the Independent Consultant retained by the State Agencies and Delmarva and its consultant, ICF, perform coordinated roles in the bid evaluation process in a cooperative manner. Upon receipt of proposals, Delmarva should promptly provide them to the Independent Consultant in order that we may perform our review. Any determination by Delmarva to reject a proposal as being non-responsive or as failing to meet threshold requirements should be subject to the review and approval of the Independent Consultant and the State Agencies. Delmarva and the Independent Consultant should both perform detailed bid evaluations, with the Independent Consultant conducting a parallel review where it has the analytical tools to do so and reviewing Delmarva's analysis where it does not. In all cases, the criteria and guidelines utilized should be those set forth in the RFP, as issued.

Delmarva has proposed to provide a confidential report to the Commission regarding the results of its bid evaluation.[10] We concur that Delmarva should provide a report, but the Company should provide a public version as well as a confidential version. Ideally, that report would be issued as part of the Independent Consultant's report on behalf of the State Agencies or at least could be submitted in the same time frame so it could be referenced in our evaluation report. The integrity of the RFP process will be best served, we believe, by the Independent Consultant working together with Delmarva to reach a consensus on bid evaluation, or where there are differences, agreeing on what those differences are and articulating them to the State Agencies. The Commission and the State Agencies will then decide whether to approve a proposal or proposals, if any, as provided for under the Act.[11] That decision will be able to draw upon the

[9] See http://www.state.de.us/delpsc/electric/irp/staffslides.pdf at 6.
[10] RFP Section 2.5 at 18.
[11] 26 Del C. § 1007(d)(3).

evaluation reports of the Independent Consultant and Delmarva which will contain their recommendations and the basis for those recommendations.

There is very little time between the date when bids are due, December 22, 2006, and the date the Commission Staff is requesting that bid evaluation be completed and an initial report be filed, February 9, 2007. Substantially in advance of the bid due date, the detailed bid evaluation process, including the key economic assumptions, should be reviewed by the Independent Consultant for appropriateness and a system and timeline established that will enable the bid evaluation to be conducted in a manner that is satisfactory to the State Agencies and consistent with the Legislative timeline.

In its comments on our initial report, Delmarva states, however, that it will only provide the State Agencies and the Independent Consultant with the key assumptions used in its economic analysis *after* it has conducted its analysis.[12] This is unacceptable. Under the Act, the State Agencies are ultimately responsible for the RFP and determinations regarding the outcome of the RFP. It is critical that the price factor evaluation and non-price factor evaluation methodologies and input assumptions be sufficiently vetted with the State Agencies through their Independent Consultant before bids are received and not after Delmarva and its consultant conduct their analyses.[13] Otherwise, the State Agencies will not have adequate assurance that the RFP bid evaluation will be properly conducted in accordance with the statutory timeframe and directives. Based on discussions we have had with Delmarva on these matters, we understand that Delmarva is now supportive of working with the State Agencies and their consultant on these matters consistent with the need to meet the statutory timeframes.

In its comments on our initial report, Delmarva states that it agrees with the establishment of a schedule to update the IRP with the highest ranking bids from the RFP process and that it will "revise the RFP to indicate that the updated IRP will be filed on or before a date agreed by Delmarva Power, the [Independent Consultant], Staff and the State Agencies."[14] We concur, but the date should be substantially in advance of the date when Delmarva and the Independent Consultant will be required to file their reports to the State Agencies regarding their recommendations regarding the outcome of the RFP process. This would be consistent with what we believe is the legislative intent, which is to provide sufficient information to the State Agencies that could support a decision on proposals in response to the RFP by the end of February 2007. With these understandings, we do not believe there are fundamental differences between the Independent Consultant and Delmarva on the relationship between the RFP process and the IRP process.

[12] Comments on the Independent Consultant's Report at 29.
[13] We address this matter in more detail in Sections VI.C.xi-xii of this report.
[14] Comments on the Independent Consultant's Report at 7.

III Objectives and Criteria for Use in Determining RFP Design Issues

In addressing RFP design issues—whether it be maximum contract size, threshold requirements, required contract terms and conditions, or price or non-price evaluation factors—it is important to have a set of objectives and criteria. Many of those objectives and criteria should flow from the Act itself. Others are reasonable to use in the design of any long-term power procurement.

The Act states that the Proposed RFP shall "set forth proposed selection criteria based on the cost-effectiveness of the project in producing energy price stability, reductions in environmental impact, benefits of adopting new and emerging technology, siting feasibility and terms and conditions concerning the sale of energy output from such facilities."[15] In approving or modifying the RFP before it is issued, the Commission and Energy Office are directed to "ensure that each RFP elicits and recognizes the value of:

a. Proposals that utilize new or innovative baseload technologies;
b. Proposals that provide long-term environmental benefits to the state;
c. Proposals that have existing fuel and transmission infrastructure;
d. Proposals that promote fuel diversity;
e. Proposals that support or improve reliability; and
f. Proposals that utilize existing brownfield or industrial sites."[16]

The State Agencies may determine to approve one or more proposals "that result in the greatest long-term system benefits, including those identified [in the above listing], in the most cost-effective manner."[17]

In preparation of its IRP, Delmarva is directed to "systematically evaluate all available supply options during a 10-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost."[18] The economic and environmental values for consideration—new or innovative baseload technologies, environmental benefits to the state, resources that encourage price stability and diversity of supply[19] -- are similar to those to be considered in the RFP process.

Various commenters, making reference to different provisions of the Act, suggest that price should or should not be an evaluation factor, that the IRP process has more emphasis on price than the RFP process, or that the enumerated values set forth in the Act require an approximately

[15] 26 Del C. § 1007(d).
[16] 26 Del C. § 1007(d)(1).
[17] 26 Del C. § 1007(d)(3).
[18] 26 Del C. § 1007(c)(1). The Act further provides that "it is the policy of the State" that electric distribution companies in their role of standard offer service suppliers shall engage in the IRP process "for the purpose of evaluating and diversifying their electric supply options, efficiently and at the lowest cost to their customers." 26 Del C. § 1002(4).
[19] 26 Del C. § 1007(c)(1)2.

equal allocation of points among the enumerated values.[20] We believe that the State Agencies should view the RFP process in a broader context.

We believe that the Legislature was interested in fostering price stability but at a reasonable price. Price stability is an important objective but only if the level of the stable price is reasonable, i.e., it is "cost-effective." Desired proposals are ones that should result in "the greatest *long-term* system benefits"—including environmental benefits and fuel diversity—"in the most cost-effective manner." It appears that the emphasis in the first IRP is to provide Delmarva and the State Agencies with the opportunity to provide cost-effective rate stability to Delmarva's SOS customers from in-state projects that are environmentally attractive and/or innovative through an expedited competitive bidding process. Based on our reading of the Act, we disagree with those commenters who assert that it is unlawful for the Commission and the State Agencies to consider price in the evaluation of bids pursuant to the RFP or that it is unlawful or inappropriate to consider the bids received pursuant to the RFP in relationship to other options considered under the IRP.[21]

If any power procurement is to be successful, it should be designed to facilitate robust participation by potential bidders. RFPs that seek long-term power contracts from investors who will invest hundreds of millions of dollars in building a new generation plant must be designed with commercial and contractual terms and conditions that will allow such projects to be financed. Absent proper structuring, participation in new-build RFPs will be lacking.

On the other hand, the RFP and power purchase agreement should be structured to provide prudent limits on the utility's and ratepayers' exposure. There should be a proper concern for the legitimate interests of the power purchaser that would be entering into a very long-term and complex contract. In this case, the Act provides for a regulatory mechanism through which cost recovery can be obtained.

A Request for Proposals should be designed to weed out those projects that do not have a high likelihood of being built, whether due to lack of site control or unlikelihood of being financed, and there should be adequate security to mitigate higher replacement power costs in the event of project failure or default, but the required security or potential damages should not be so high as to deter participation by qualified bidders.

Overall, there should be a fair allocation of risk between the utility and its customers, on the one side, and the potential sellers who are seeking to invest hundreds of million dollars in new capital assets, on the other side. A key reference point in ascertaining a fair risk allocation is what industry practice is on any particular RFP design or contract issue. If risks are unduly allocated to sellers, there can be three types of adverse impacts from the customer perspective: (1) inadequate participation in the RFP process; (2) potential bidders participate but they bid substantially higher prices than they otherwise would to cover the additional risks; and (3)

[20] See comments of Bluewater Wind at 18-20, Firestone and Kempton at 2-5, and SCS Energy at 7.
[21] See reply comments of Firestone and Kempton at 3, Green Delaware reply comments, and Bluewater Wind mark up to Section 2.2 of the RFP.

potential bidders participate but the winning bidder(s) are not able to finance and build their project(s) due to the excessive risks.

In reviewing the Proposed RFP, the Independent Consultant has utilized the objectives and criteria outlined in this section. Our evaluation and recommendations should be viewed in this light. In its reply comments, Delmarva takes the position that its Proposed RFP reflects a "complex relationship between bid block size, corporate structure, security requirements, and the risk of default borne by Delaware customers" and proposes that it should not be tampered with.[22] However, a fundamental problem with Delmarva's proposal is that its proposed minimum entry requirements (primarily, credit, contract size, a firm energy requirement, and "regulatory out" provision) would likely result in few if any qualifying bids, a matter we address in the next two sections. This is not a desired result for a competitive procurement, especially one directed by a state legislature.

Our approach has been to encourage generation bids from interested parties through a procurement process that is based on commercial contract terms prevalent in the industry, as informed by the objectives and limitations set forth in the Act. Negative attributes of projects, such as contract sizes that are larger than optimal, will be taken into consideration in the bid evaluation.

We have focused more concern on mitigating Delmarva SOS customer exposure than have some of the prospective generation bidders, and we have sought to balance environmental and economic concerns. We appreciate the contributions of the various participants to this proceeding. In the following sections, we address individual components of the proposed RFP, with our recommendations, and address the relationship between the key components addressed by Delmarva above in Section V.B of this report.

IV Contract Size, Plant Location, Bid Deposit, Products to be Purchased, and Regulatory-Related Issues

A Contract Size

Delmarva proposed that the maximum amount of capacity, energy and ancillary services to be purchased under a PPA be 200 MW, with a minimum amount of 50 MW for a non-renewable energy project and 25 MW for a renewable project.[23] The purchase of electric power must come from new, incremental generation capacity located in Delaware.[24] Bidders may propose a PPA

[22] See page 2.
[23] RFP Section 1.1 at 2.
[24] This would include the full capacity of a new generation unit, even if another generating unit at the same plant site was retired. However, if a generation unit is repowered to increase its capacity, only the incremental, new capacity would be considered for a PPA under the RFP. RFP Section 1.1 at 1.

term for a minimum of 10 years and a maximum of 25 years, with an in-service date on or before June 1, 2013.

Maximum Contract Size

Delmarva has stated that the 200 MW maximum contract size is based on a desire not to depend too heavily on a single source for Standard Offer Service supply. In this regard, it states that last year, its SOS customers consumed less than 200 MW during two percent of the annual hours and that the average hourly load of Delmarva's residential and small commercial customers is 400 MW. Delmarva further states that this size "supports compliance with the legislation requiring 30% of SOS supply to be sourced from [the] wholesale market through a bid/auction process."[25] Subsequently, Delmarva has provided data showing that the maximum peak load for Delaware residential and small commercial SOS customers from October 2004 through September 2005 was 1,028 MW.

Three commenters have expressed an interest in building new generation in Delaware and in potentially submitting proposals in response to the RFP. Two of them—NRG and SCS Energy—have stated that the 200 MW limit is too low and that it would be insufficient to support financing of the size of plant that would be economical to build. NRG, which owns the coal-fired Indian River power plant in Millsboro, Delaware, is planning to build an integrated coal gasification combined cycle ("coal IGCC") plant. It states that the economics of these plants require that they be sized upwards of 500 MW. Earlier, this year, NRG announced a plan to repower Indian River, which would include a new 630 MW coal IGCC unit at the plant site.[26]

NRG argues that Delmarva's 200 MW limit is not well supported because (a) it does not take into consideration a size that is necessary to support a new, economical coal IGCC plant, (b) the 30% wholesale competitive procurement requirement in the Act applicable to IRPs is a minimum requirement and does not suggest a maximum capacity purchase size, and (c) it does not take into consideration load growth in Delaware and what loads will likely be six years from now when a coal IGCC plant could commence operation.[27]

SCS Energy states that the Act provides that the RFP should recognize the importance of "new or innovative technologies," including coal gasification (which is specifically referenced in the Act), and that coal IGCC projects planned nationwide are at a scale of 600 MW or more. SCS Energy recommends increasing the maximum contract size to 1,000 MW, the size of Delmarva's current peak load for residential and small commercial customer SOS.[28] NRG recommends that the maximum size limit be increased, but does not recommend a specific maximum contract size.

Bluewater Wind, which plans to develop an offshore wind project off the coast of Delaware, has proposed that the limit be stated as an energy limit, rather than a capacity limit, so that lower

[25] Delmarva's presentation at the August 18, 2006 workshop, http://www.state.de.us/delpsc/electric/irp/dpslides.pdf at 7.
[26] See Workshop transcript, http://www.state.de.us/delpsc/electric/irp/0818transcript.pdf at 83-84.
[27] NRG comments at 4-11.
[28] SCE Energy comments at 3.

capacity factor projects, such as wind, could propose a higher level of capacity.[29] An offshore wind project might have a capacity factor in the 35%-45% range while a coal IGCC plant might have an availability factor in the 80-85% range and a capacity factor of approximately 70%.

From our perspective, both Delmarva and the commenters express legitimate concerns. Delmarva is concerned about the size of the potential exposure it and its SOS ratepayers would have to a single generating source and contract. The developers are concerned as to whether a 200 MW contract would support the financing of a plant that must be much larger to be economical.

There is a risk that a stable-priced contract with a generator could become substantially over-market during the 2012-2037 period when the generator could be making power sales under the contract if electric power prices decline or are stagnant. If that were to occur in a sufficiently substantial magnitude, customers might leave SOS for the competitive market leaving fewer customers to bear higher unit over-market costs. The Act does provide the Commission with the ability to protect SOS customers by allocating some degree of over-market costs to distribution customers,[30] but this is a fallback mechanism, not a preferred outcome. Hence, there should be some limitation on the size of long-term contracts that Delmarva should enter into to support Standard Offer Service. We agree with NRG that current SOS loads are not adequate information. We have asked Delmarva to provide projections of its load duration curves for residential and small customer Standard Offer Service for the next 10 years,[31]

However, we believe we have sufficient information to conclude that 600 MW or more is too large a contract from a customer exposure perspective. We also do not believe that a developer of a 500 MW or 600 MW project will require a 500 MW or 600 MW contract from Delmarva to obtain financing. In the industry, project developers and their investors have been willing to assume a certain amount of “subscription risk” and/or “merchant risk.” Subscription risk is the risk that a certain portion of a plant’s capacity and energy is not locked up under a long-term PPA. Merchant risk is the extent to which a plant’s investors are willing to accept market price risk. Hence, a developer in signing a PPA for a portion of the plant’s capacity might be willing to accept a certain amount of subscription risk for the remaining capacity, but plant lenders and equity investors would want additional long-term contracts to be entered into prior to construction or would need to be willing to assume merchant (or market price) risk. In the late 1990’s, a variety of natural gas plants, primarily combined cycle, were built on a merchant basis, with a relatively high rate of financial failure due to lower “spark spreads” (profit margins) than projected. This factor coupled with the higher risk associated with more capital intensive and less technologically proven projects would make plants that are primarily merchant unlikely to be financed.

[29] Bluewater Wind comments at 10.
[30] See 26 Del C. § 1010(c).
[31] We also suggested that Delmarva provide the same information for its Delaware distribution customers in light of the potential for assessing some portion of SOS charges to this set of customers, even though this scenario is not likely to be realized.

In light of the foregoing, we recommend that the maximum contract size should be increased but that an Exposure category should be included as part of the economic evaluation to take into consideration that purchases of capacity and energy at or below the maximum contract size proposed by Delmarva is more desirable than purchases above that level. Specifically, we recommend that the maximum contract amount for any single project be limited to 400 MW. The Exposure category, addressed in Section VI.C.vii of this report, would take into consideration the amount of capacity in excess of 200 MW, the expected capacity factor of the project, bidder credit rating, the extent to which the contract capacity would be dispatchable, and contract duration. We believe all these factors are relevant.

The 400 MW amount would represent 80% of a 500 MW plant and 63.5% of a 630 MW plant. We believe that this subscription percentage would leave a reasonable amount of subscription and/or market risk for project developers in this context. With respect to an offshore wind project, we believe a 400 MW limit is also appropriate.. We note that the Cape Wind project currently planned for offshore Massachusetts is in the 420-468 MW range and a project planned for offshore Long Island is planned for 140 MW.

In our initial report, we solicited participants' comments on our proposal on maximum contract size. Delmarva continued to advocate for a 200 MW maximum contract size while NRG, SCS Energy and Bluewater Wind proposed a 600 MW maximum contract size (Bluewater Wind proposed a 600 MW maximum nameplate capacity contract size for wind only). Messrs. Firestone and Kempton suggested that the maximum contract size be based on the energy output of a 400 MW plant at a 100% capacity factor so that a 900 MW wind plant at a 40% capacity factor would come within the size limit. Several parties have requested that we provide a more detailed rationale for our recommendation. We will do so and will respond to a variety of points made by the commenters.

Delmarva asserts that under the Act no more than 70 percent of its SOS requirements may be acquired through the RFP process.[32] Under 26 Del C. § 1007(c)(1)1:

> As part of its IRP process, DP&L shall not rely exclusively on any particular resource or purchase procurement process . . . At least 30 percent of the resource mix of DP&L shall be purchases made through the regional wholesale market via a bid procurement or auction process held by DP&L. Such process shall be overseen by the Commission subject ot the procurement process approved in PSC Docket #04-391 as may be modified by future Commission action.

We agree that this statutory provision creates a limiting factor on the maximum contract size allowable under the RFP process. Basically, since at least 30 percent of Delmarva's SOS sales must be procured pursuant to the requirements purchase RFP process approved by the Commission in another proceeding, no more than 70% of the requirement may reasonably be procured under long-term contracts pursuant to the RFP process.[33]

[32] Comments on Independent Consultant's Report at 11.
[33] While it is possible to procure a substantial amount of generation under the RFP, sell it back to the market and acquire 100% of the SOS requirements service under three-year contracts, we understand that the legislative intent

In assessing this limitation, we would look at both capacity and energy on an annualized basis and the capacity factors of baseload generators that could provide stable pricing and are likely to bid in the RFP. Based on our knowledge and information provided by ICF, a capacity factor for coal gasification projects of approximately 70% is a reasonable assumption to use. These plants can be expected to have availability factors in the 80-85% range once mature and are likely to have a degree of ramp down capability in off-peak hours (ramping down to 50-70% of their full load capability).

At our request, Delmarva provided a preliminary forecast of Delaware residential and small commercial (RSCI) customers for 2006-16. This weather-normalized projection shows a decrease in loads (before any migration) from 2004-05 that does not reach 2004-05 levels until 2011 and a 2% increase per year thereafter. Given this low level of load growth, we produced a second projection with a 2% yearly increase from 2004-05 levels (we note that according to a recent Department of Energy report, PJM is projecting annual load growth in the Delmarva peninsula at 2.7% over the next five years with significant, continuing load growth over the longer term).[34] During the 2012-16 period (the early years when a coal gasification project could come into service), a 400 MW unit would produce 62-67% of RSCI load based on Delmarva's estimates and 55-60% based on the alternative projection without migration.[35] With 15% migration, the same unit would produce 73-79% of RSCI load based on Delmarva's estimates and 65-70% based on the alternative projection.

Based on this analysis, we believe a 400 MW maximum contract size is supportable for the RFP. However, if the Commission desires to limit the size due to concerns about migration risk, we would recommend that the limit be reduced to 350 MW (the unit would produce 64-69% of RSCI load based on Delmarva's estimates and 57-62% based on the alternative estimates). Delmarva suggests a maximum limit of 280 MW based on the statutory provisions, but that is based on historical loads and a 100% capacity factor unit, which is not realistic.

If a bidder bids a high capacity factor plant with no significant flexibility in being able to ramp down from full load to a minimum operating level such that its capacity factor would be approximately equal to its target equivalent availability factor, the maximum contract size should be adjusted for such a unit by multiplying the product of the maximum contract size by 70% divided by the target equivalent availability factor ("EAF"). For example, for a 400 MW maximum contract size and an 80% target EAF, such a unit would have a maximum contract size of 400 x .70/.80 or 350 MW.

Delmarva did not provide any projected load duration curves, as we requested, but Delmarva did provide historical October 2004 to September 2005 load data for Delmarva's residential and small commercial SOS customers. This data shows a peak load of over 700 MW and during much of the off-peak hours, energy consumption is in the 200-400 MW range. From this data and potential reduced loads through customer migration, Delmarva concludes that a 200 MW

was to promote diversity among potential sources of energy and capacity, hence, imposing some degree of limitation on energy and capacity to be procured under the RFP process.

[34] U.S. Department of Energy, National Electric Transmission Congestion Study (August 2006) at 42 n.44.

[35] See Appendix C.

contract size should be the maximum allowed and that a 400 MW contract size, let alone a 600 MW contract size, would be excessive.

We are not overly concerned that there will be many hours in the year that the output of a plant under a 400 MW contract may be greater than RSCI SOS load. These hours are lower value hours, as Delmarva correctly points out, but the relative cost and benefit of a baseload unit will be taken into consideration in the economic analysis that will be conducted by Delmarva and its consultant. Moreover, the plant under contract to Delmarva may have substantial ability to reduce its output during offpeak hours when costs are low. Any excess power could be sold back to the market on a spot basis or under term contracts[36]. We also note that with increasing load growth, off-peak loads will also increase. There are price stability benefits from contracts of this size.

Our fundamental concern with Delmarva's position is that it does not take into consideration the size of plants that could be economically built and the size of contracts that might support financing them. Our fundamental issue with those seeking a 600 MW maximum contract size is that they do not take into consideration that the purpose of the RFP is to solicit a long-term physical hedge for Delmarva SOS customers for price stability purposes and that too large of a contract is problematic for customers.

Delmarva's concern about a "death spiral" if the long-term PPA prices greatly exceed market prices does not take into consideration that the Legislature has addressed this potential problem by authorizing the Commission to either restrict retail competition or add a nonbypassable charge if this eventuality were to lead to large scale migration of small customers.[37] Delmarva points to instances where long-term contracts have been or would have been economically

[36] Delmarva could sell its entitlements to capacity and energy from the unit under contract and the net benefit or cost (revenues minus PPA costs) would accrue to Delmarva's SOS customers, with the impact of stabilizing SOS rates over the term of a 10-year to 25-year PPA. In periods when power prices are very high, the impact will be that SOS costs will be lower than they otherwise would be. When power prices are lower than the PPA price, SOS costs will be higher than they otherwise would be. Once the plant is up and running, Delmarva could sell its entitlement to the unit on a term basis. Maine's experience has been particularly instructive in this area. Central Maine Power Company ("CMP") has a number of long-term PPA's, most of which are unit contingent contracts. Maine, like Delaware, has a competitive retail market and the utilities, under Commission supervision, procure standard offer service. RFPs to sell CMP's PPA entitlements have been conducted simultaneously with RFPs to procure standard offer service. Several times, for three-year periods, the winning bidder for SOS service has bid to purchase CMP's PPA entitlements as part of a package (so-called "contingent bidding"). The Maine Public Utilities Commission has found this approach to have benefits for ratepayers:

> Through its experience in conducting the standard offer bid processes, the Commission has found that contingent bidding can be a means to maximize the value of utility power entitlements to the benefit of the utility's ratepayers. This is because the business risk for a bidder can be reduced when load obligations and the resources to serve that load are simultaneously obtained. Reduced risk translates to lower costs and a higher value for the entitlements.

See http://www.maine.gov/mpuc/industries/electricity/electric%20restructuring/appendixe.htm.

[37] See Section IV.F of this report.

disadvantageous for ratepayers (pp. 13-14) and one could point to other situations where long-term contracts would have been advantageous for ratepayers (such as California, which now requires its utilities to solicit power under long-term contracts), but the ultimate question should be determined by the State Agencies after bids have been received and evaluated and compared in the context of the IRP. We do not think that it is appropriate at this stage to unduly limit bids from generators. Concerns about impacts on Delmarva's credit rating will also be considered in the bid evaluation (see Section V.C.viii of this report).

We should also point out that there is a public interest in fostering additional generation to be built in Delaware. There is a deficiency of generation relative to load on the Delmarva peninsula which creates congestion and higher market prices. Additional generation in Delaware is part of the solution and there is a dearth of industry participants willing to build new generation in the absence of substantial support through long-term contracts. New generation would have direct impacts on Delmarva's customers through a long-term power purchase and indirect positive benefits through creating additional local supply to meet the demand. This situation has led other states, such as California and Connecticut, to direct their utilities to solicit proposals for long-term power purchase agreements to support new generation plants.

Our explanation in support of a 400 MW maximum contract size should address NRG Energy's objection that our proposal has no rational basis and is simply a "split the difference" compromise.[38] NRG Energy states that the Commission should require the Independent Consultant to undertake an analysis of the ability of developers to obtain financing for a base load power plant, using innovative technology, with a 400 MW contract for a 630 MW plant.[39] NRG goes on to say that it is skeptical that such an analysis will support the proposed 400 MW size limit. NRG further states that the 400 MW contract size limit will result in additional unit costs to Delmarva ratepayers either as a result of downsizing the unit or more costly financing for a plant of optimal size.[40]

We do not believe that the analysis proposed by NRG is necessary. Financeability of projects is an important consideration. However, the question of sizing of a power sale contract must be evaluated in a commercial context and under the limitations set forth by the Act. It is not reasonable for a distribution utility to "over-hedge" itself substantially, even if the results are somewhat higher unit purchase costs or difficulties a developer would have in financing its projects. Historically, we are aware of projects with subscription percentages in the 56% to 80% ranges that were financed and built. We realize coal IGCC (and offshore wind projects) will likely have a higher bar than more conventional technologies. However, there are other opportunities for NRG and others to hedge their energy market price risk through bilateral contracts with other buyers or swaps or other financial transactions and, in our experience, the financial markets for project equity have become more flexible in this regard in the last few years. There needs to be a line drawn somewhere, and we believe that 400 MW is the maximum level that could be justified under the Act and that does not produce unreasonable "over

[38] See Comments of NRG Energy, Inc. on Independent Consultant's Report at 4.
[39] Id. at 4.
[40] Id. at 5.

hedging" for Delmarva's SOS customers while providing developers, such as NRG, a reasonable "anchor tenant" power contract to support development and financing of their project.

NRG states that our initial report proposes a 200 MW limit on non-dispatchable power. We did not intend to propose any such limit. We proposed that dispatchability should be one of the factors to be considered in a 5-point category for exposure that takes into consideration contract sizes above 200 MW. We address this issue in Section VI.C.vii of this report.[41]

In its term sheet markup, Bluewater Wind proposes a contract limit of 600 MW nameplate capacity for a wind project, without specifying the rationale. In its earlier comments, Bluewater Wind proposed that the limit be based on energy, not capacity, a suggestion seconded by Messrs. Firestone and Kempton. While the energy from a 600 MW wind project might be less than that from a 400 MW baseload unit on an annual basis, the intermittent nature of wind energy would result in energy produced that could be substantially above 400 MW when loads are low and conversely there could be little or no production when loads are high. This would lead to more of a mismatch in terms of a hedge and would produce less value for Delmarva's customers. We also note that offshore wind developers do have flexibility in sizing projects and that a 600 MW wind project would be twice the size of the largest wind project in the United States and would be approximately 30% larger than the offshore wind project being developed for offshore Cape Cod. It would represent by far the largest proportion of installed wind capacity and energy relative to load of any utility in the U.S. and perhaps internationally. For these reasons, we believe that a 400 MW nameplate capacity limit with respect to UCAP and energy produced from that nameplate capacity is appropriate for wind and other intermittent renewable energy projects, as well as other projects.

SCS Energy is generally in accord with NRG and asserts that "other states that have supported IGCC projects have done so through PPAs of at least 600 MW."[42] While the states are not specifically named, it is unlikely that the customer class that would support it is as small as Delmarva Power's SOS customers. SCS argues that the greater exposure resulting from a 600 MW contract should simply be an evaluation factor. However, we do not believe that this is a viable option under the Act or would be reasonable for Delmarva's SOS customers. RFPs typically have maximum size limitations, and we believe that this one should as well.

Minimum Contract Size

We do not see the value of having a minimum contract size. Smaller projects, such as landfill gas projects, can be economical and provide substantial long-term environmental benefits. The proposed minimum size requirements would effectively exclude such projects. In its reply comments, Delmarva stated that it reduced its minimum size requirement for renewables such as landfill gas, but almost all landfill gas projects are substantially smaller than 25 MW. Delmarva states that the size should be substantial enough to have a meaningful economic impact, but this appears to run counter to Delmarva's concerns for diversity. We believe the proposed restrictions are unnecessary and could unreasonably limit potential opportunities for Delaware

[41] In submitting a bid, a party will specify the operational characteristics of its proposed project.
[42] Reply Comments of SCS Energy at 2.

SOS customers. Hence, we recommend that the minimum contract size requirements be eliminated.

B Plant Location

The Proposed RFP, consistent with the Act, provides that it is open to any new generation project located in Delaware, whether or not it is located in Delmarva's service territory.[43] Bluewater Wind, which states that it is planning to submit a bid for development of a wind energy facility off the shore of Delaware, has proposed language that would include an offshore wind project as being, in the language of the Act a "new generation resource within Delaware." Specifically, Bluewater Wind proposes that the following language be added to the RFP at the end of the section on Location (Section 1.4): "For New Generation in or on Delaware's jurisdictional portion of the Delaware Bay or the Atlantic Ocean, whether the waters of the State of Delaware or the Waters of the United States or within its Exclusive Economic Zone from 12 to 200 Nautical Miles, 'in Delaware' shall mean that the New Generation's power cables make landfall within the Sate of Delaware and originate in Delaware and/or Federal waters only."[44] We concur with this recommendation. We believe that it is consistent with the legislative intent that an offshore wind project whose transmission lines make landfall in Delaware should be considered as being "within Delaware" for purposes of the RFP.

C Bid Fee

The Proposed RFP requires that bidders pay a non-refundable bid fee of $10,000 at the time that bids are submitted.[45] This is not unusual for competitive power procurements, especially those that are seeking amounts of capacity in the range sought. While none of the potential bidders objected to this fee, the Public Advocate recommended that the bid fee be reduced to $3,000.[46]

There are two types of bid fee, refundable and non-refundable. Refundable fees tend to be larger and are intended to prevent a bidder from "walking away" from its bid. Non-refundable fees are intended to offset some of the cost of bid evaluation and are set at levels to reflect some bidder commitment to the process but not high enough to deter participation. We concur with Delmarva's proposal, with the proposed modification that for projects less than 50 MW in size, the bid fee should be $200 per MW ($4,000 for a 20 MW project), with a minimum $500 bid fee. Delmarva opposes the sliding scale reduction for smaller projects, stating that the RPS provides opportunities for smaller renewable projects and that accommodation here is not necessary. However, the RPS is a requirement on the purchase of renewable energy credits by load serving entities. It does not involve the purchase of capacity and energy, which is the primary subject of this RFP. We believe our recommendation on bid fees is appropriate and is consistent with our approach of attempting to facilitate robust bidding.

We recommend allowing a bidder to propose up to three variants for each bid deposit per proposed generation resource—differences may include pricing or price formulas, contract term,

[43] RFP Section 1.4 at 3; see 26 Del C. § 1007(d)
[44] Comments of Bluewater Wind at 11.
[45] Section 1.1 at 2.
[46] Initial Comments of the Public Advocate at 4.

guaranteed completion dates, or other variables. If a bidder proposes a project on a different site or using a different technology, this will constitute a separate proposal which will be subject to a separate bid fee.

D Products to be Purchased

i. Introduction

The Act requires that the RFP contain a proposed form of output contract "which shall include capacity and energy and may include ancillary electric products and environmental attributes between the electric distribution company and developers of new generation facilities."[47] Capacity, energy, ancillary services and forms of environmental attributes are referred to as "products" in the electric power industry. This section addresses the nature and definition of the products Delmarva proposes to purchase.

ii. Energy: Unit Contingent vs. "Firm"

Delmarva proposes that the Seller be responsible for delivering energy from the proposed plant and be responsible for the cost of replacement power whenever the plant is unavailable to produce energy. Specifically, Delmarva states that:

> The size and form of the energy contract must be comparable to the energy output expectations of the New Generation. Delmarva will structure the energy contract based on a contractual capacity factor intended to reflect the operating characteristics of the New Generation whereby the bidder is at risk for under-performance.[48]

The Proposed RFP also provides that unavailability of the generating unit shall not relieve the Seller from the obligation to deliver energy, even if it is due to a Force Majeure Event.[49] Failure to deliver a Product, such as energy, at any time (after commercial operation has occurred) is an Event of Default that shall require the Seller pay "all of Buyer's costs of obtaining such Product from parties other than Seller (i.e., cost of cover)."[50] Failure to deliver any Product five times during a calendar year shall entitle Delmarva to terminate the PPA and seek damages for long-term replacement power costs.[51] The Delivery Point is required to be in the Delmarva Zone.

NRG states that there should be no obligation to require delivery of "system firm" power when a plant suffers from a forced outage.[52] Since the PPA has capacity payments based on Unforced Capacity (addressed below), NRG states that it should not be obligated to obtain or pay for replacement power in the event of a forced outage because it will already experience reductions in capacity payments. In fact, NRG proposes that it have the right, but not the obligation, to deliver energy when the plant is not available. Bluewater Wind, in its comments, questioned

[47] 26 Del C. § 1007(d).
[48] Proposed RFP Section 1.5 at 3.
[49] Proposed RFP Key Commercial Terms at 12.
[50] Key Commercial Terms at 9, 10.
[51] Key Commercial Terms at 10.
[52] Comments at 30.

how Delmarva would structure a PPA for a wind project based on its “anticipated capacity factor.”[53]

Delmarva’s proposed energy product is highly unconventional for an output contract for energy from a specific generating unit. The obligation to provide replacement power whenever a unit experiences an outage would make such a contract problematic for a developer to finance.

The typical industry practice for a dispatchable power project is to adjust a Seller’s capacity payments based on a Project’s Equivalent Availability Factor. In this manner, a Seller’s substandard performance is penalized through reduced capacity payments and the Buyer is effectively compensated through a form of liquidated damages by making reduced payments to the Seller. Equivalent Availability Factor (EAF) differs from the Equivalent Forced Outage Rate used in adjusting net summer capacity to Unforced Capacity in that EAF explicitly takes into consideration the length and frequency of planned outages in evaluation of plant performance.

In structuring these capacity payment adjustment provisions, the value of performance during peak periods can be recognized. In the mark-up to Delmarva’s proposed Key Commercial Terms, we have proposed specific capacity payment adjustment provisions that emphasize the importance of superior performance during peak daily and seasonal periods. Typically, a coal project would have high capacity payments and low energy payments so there would be a strong incentive to maintain high availability.

Wind energy projects produce intermittent energy and relatively little in the way of recognized capacity. Typically, such Sellers are paid for the energy that they produce, sometimes with an outer limit maximum limitation. A Seller of a wind project output would provide whatever capacity is produced under applicable ISO rules.[54] Typically, a wind energy contract would have high energy payments and low capacity payments. In fact, in many wind energy contracts, the capacity is provided to the Buyer but the sole compensation to the Seller is in the form of $/MWh payments. In this manner, the Seller bears the risk in terms of the ability of the wind energy project to produce energy. With small, if any, capacity payments, an equivalent availability adjustment provision is not necessary for a wind energy project.

The Seller should not have the option to provide replacement power when its plant is unavailable or is not called upon to produce energy, as proposed by NRG. The Seller could use that right to deliver energy when the market price is lower than the contract price, which would deprive Delmarva and its customers of an economic benefit. It is standard industry practice that a Seller in a unit-contingent power contract would not have the option to provide replacement power from another source.

We recommend that Sellers have the ability to bid unit-contingent energy, as described above. It is acceptable to provide bidders with the opportunity to bid firm energy, as Delmarva

[53] Comments at 10.

[54] Under current PJM rules, a new wind farm would initially receive a capacity credit equal to 20% of the sum of the nameplate ratings of the wind turbines at the wind farm. When operational experience is obtained, the capacity credit is based on the plant capacity factor during summer peak hours. See PJM Manual 21, Rules and Procedures for Determination of Generating Capability, Appendix B (Revision 04, August 15, 2005).

proposes. However, since no potential bidder has expressed interest in bidding firm energy, we would recommend that the standard contact be based solely on a unit-contingent energy product.

In its reply comments, Delmarva argues that a unit contingent contract would create various problems for it and its customers regarding the supply and receipt of full requirements service and management of the associated risks.[55] However, these risks should be manageable by one or more energy marketers (regardless of whether they would buy the unit power from Delmarva under a back-to-back contract or would supply power on top of that provided by the unit power contract) and/or Delmarva. Moreover, the PPA itself will have strong risk mitigants through the availability adjustment provisions, security, and other contract provisions.

While NRG and SCS support a unit contingent contract approach, NRG, in its reply comments, continues to push for the option, but not the obligation, to deliver energy from the market when its plant is not available but this time, at the lower of the contract price and the market price and have the plant be considered available for capacity payment adjustment purposes.[56] While this revised proposal addresses some of our concerns, we still find it to be unacceptable. The capacity payment adjustment provisions are a form of liquidated damages to be assessed against generators for substandard plant availability. Liquidated damages may be higher or lower than actual damages in any particular case, but provide a mutually agreeable way of relating payment to performance and the value of performance. If one party could provide power from another source only during periods when it would be less costly to it than incurring the impact of liquidated damages, it would skew the impact of the liquidated damages solely to that party's benefit. While this may benefit NRG, it is not fair to Delmarva or its customers. Hence, we cannot support NRG's proposal.

iii. Capacity – UCAP

Delmarva proposes to pay for capacity in the form of Unforced Capacity (or UCAP). Specifically, Delmarva will pay a Seller for the amount of UCAP that receives recognition by PJM. The amount per kW-month will be as specified in the contract. UCAP is the installed net summer capacity rating of a generating unit, adjusted by its equivalent forced outage rate.[57]

PJM has rules for assigning Equivalent Forced Outage Rates for different types of generating facilities in their initial years of operation (since there is no substantial performance history for a new unit, the historical track record of similar units is applied).[58] Delmarva proposes that in the event PJM has not assigned a UCAP amount to the project, it will allow for an automatic adjustment once PJM has assigned a UCAP amount to the unit.

[55] See pp. 15-18.
[56] NRG comments at 12-13.
[57] "Unforced Capacity" shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership or the contractual rights to the capacity of the unit." Section 1.72, PJM Reliability Assurance Agreement (August 30, 2005).
[58] See PJM Manual 21: Generator Resource Performance Indices at 15 (Revision 14, June 1, 2005).

There are several issues presented. First, should the seller be required to deliver UCAP under the PPA? Second, should Delmarva utilize UCAP for payment purposes or a variant that would adjust capacity payments based on Equivalent Availability Factor and would take into consideration the timing and value of outage periods? Finally, should be the capacity payment adjustment provisions during the first several years for innovative technologies, such as coal IGCC, where there is little in the way of performance track record, an issue raised by NRG.

First, all sellers should be required to provide UCAP to Delmarva under the PPA. With regard to the second question, we recommend use of a capacity payment adjustment provision that will be reflective of UCAP, but will also take into consideration planned outage time and the greater importance of reliable performance during peak periods compared to non-peak periods. We have proposed a specific provision in the mark up to the term sheet that is part of the RFP.[59] Contrary to Delmarva's assertions,[60] there is no inconsistency between using this methodology for payment purposes and PJM operation. In fact, an equivalent availability adjustment provision is commonly used in the industry for unit contracts.[61]

NRG proposes a floor for UCAP during the first three years of operation so that it would obtain the higher of UCAP credited by PJM and a specified floor value, suggested as 65% for Year 1, 75% for Year 2, and 80% for Year 3. In the formula we plan to propose, a Seller will be able to propose guaranteed availability targets for different contract years. Bidders can propose the performance levels they are comfortable standing behind and that level of performance will be evaluated by Delmarva and the Independent Consultant.

iv. Ancillaries and Environmental Attributes

The Proposed RFP requires that bidders supply, with the capacity and energy from a new generation unit, any and all ancillary services and environmental attributes that the unit may provide that would be used to serve SOS load. While the Act permits Delmarva to buy ancillaries and environmental attributes ("EAs"), the Act does not require it. However, it is common for PPAs to incorporate these products, and we support their inclusion based on the conditions outlined below.

1. Delmarva should specify that it is the ancillary services recognized by PJM that it desires to purchase, and each bidder should specify which products it is proposing to provide and the limitations under which it can provide them.[62] Delmarva should specify that it will evaluate the benefits of providing ancillary services in the bid evaluation.

2. Projects that will not provide ancillary services or provide only limited ancillary services (such as a wind product) will not be "penalized" in the bid evaluation. Their capacity,

[59] See Attachment 3. Another option is to use UCAP, with limitations on planned outages and adjustments based on timing of outages.
[60] See reply comments at 18.
[61] The same GADS data used to determine UCAP can be used for purposes of calculating the capacity payment adjustment based on equivalent availability.
[62] Examples of ancillary services are spinning reserves, regulation and operating reserves.

energy, and renewable energy credits will be fully valued. There is no requirement for a bidder to bid an ancillary service that its proposed generation plant cannot provide.

3. Delmarva should exclude “Environmental Attributes” and “replacement reserves” from the definition of “Ancillary Services.”[63] They are not ancillary services, as defined by PJM. While NRG asserts that a Seller should not be required to provide any Ancillary Service that is created after the execution of the PPA,[64] we recommend that Sellers should be required to provide a newly defined Ancillary Service (a) to the extent it can be provided by the generating unit without any material increase or operating or capital costs or material decrease in revenues or (b) if there are material costs and/or changes required and the Buyer agrees to hold the Seller harmless in order to secure delivery of the future product.

4. Delmarva has proposed a definition of “Environmental Attributes” that is overly broad. The Proposed PPA appears to suggest that all of a Seller’s allowances for sulfur dioxide, nitrogen oxides and carbon dioxide must be conveyed to the Buyer. At the same time, the Proposed RFP states that the Seller is fully responsible for compliance with all environmental laws and for having all the required allowances, offsets, and credits it needs relative to the output from Seller’s plant. In our draft RFP, we proposed that “Environmental Attributes” should be redefined to incorporate two things: (a) renewable energy credits (“RECs”) from eligible renewable energy resources pursuant to the Delaware Renewable Energy Renewable Portfolio Standard or any other renewable portfolio standard (or any other claim based on the renewable nature of the energy produced by the plant), and (b) any claims that the production of energy purchased by Delmarva has the impact of reducing emissions elsewhere. We proposed specific language in our mark up to the RFP to implement this recommendation. Bluewater Wind has expressed concern that Environmental Attributes other than RECs would be required to be conveyed to Delmarva without being properly valued. To address this concern, we recommend modifying the definition of “Environmental Attributes” to include only RECs so that sellers, such as Bluewater Wind, would retain any potential Environmental Attribute value that would not be encompassed within the transfer of RECs.

5. There should be a limit to the number of renewable energy credits to be purchased by Delmarva under the PPA based on the expected output of the proposed plant and Delmarva’s projected obligation under the Delaware Renewable Portfolio Standard relative to SOS load. The RPS percentage increases from 1% in the compliance year beginning June 1, 2007 to 10% in the compliance year beginning June 1, 2019. For the compliance year beginning June 1, 2013, the percentage is 5%. There is one REC created for each MWh of energy produced by an eligible renewable energy facility. We recommend that there be a cap on the amount of RECs that Delmarva would purchase based on a projection of its SOS load in future years multiplied by its projected RPS obligations. We asked Delmarva to provide estimates of projected loads and its estimated

[63] See Key Commercial Terms at 3.
[64] Comments at 34.

REC purchase obligations and make a recommendation on a REC purchase cap, but we have not received a response. Nor has Bluewater Wind made a recommendation on this point. Based on Delmarva's load projections assuming a small amount of migration, the RPS minimum percentages per compliance year, the 70% limit on RFP procurement, and recognizing that RECs can be banked for three years, we recommend the following REC purchase limits:

2010	65,000
2011	85,000
2012	105,000
2013	135,000
2014	150,000
After 2014	175,000

We believe that these are reasonable limits for RECs to be sold under a PPA to Delmarva and that Delmarva should be required to purchase up to these amounts (subject to contract terms). This equates to production from 19 MW facility at a 40 percent capacity factor in 2010 to 50 MW in 2014.[65] In order to properly evaluate the benefits of RECs included in any bid, Delmarva will need to generate REC price projections.

v. Delivery Point

Delmarva proposes that the Delivery Point for energy and capacity to be provided by Seller will be the Delmarva Zone. The Delmarva Zone is the aggregate of busses as listed on the PJM website and aggregated by Delmarva. Delmarva states that it will not be responsible for designating proposed projects as a network resource.

Initially, it is our understanding that any generator that would be eligible to submit a bid in the upcoming RFP would propose a point of interconnection in the Delmarva zone, as it is our understanding that this includes all of Delaware. NRG asserts that the Delivery Point should be the plant's bus bar so that the risks of congestion and marginal losses are not borne by Seller.[66]

Apparently, the issue appears to be the difference in locational marginal price (congestion and marginal losses) between that of a plant's interconnection point and that of the Delmarva zone (an aggregate of nodal points). In our initial report, we recommended that a Seller be able to deliver to an interconnection point within the Delmarva zone and for Delmarva to take into consideration the risk of marginal losses and congestion in its bid evaluation.

Both Delmarva and NRG expressed concern about our recommendation. Delmarva contends that it is critical that customers not be subject to delivery and congestion risk.[67] NRG expresses two concerns: (1) that Delmarva could designate a self-build project as a network resource, which would give it an undue preference; and (2) Delmarva's modeling of transmission and

[65] See Appendix D.
[66] Comments at 29.
[67] Comments on the Independent Consultant's Report at 18-19.

congestion losses should take into consideration network upgrades, and, if transmission losses and congestion were to make a difference between winning and losing, a bidder should be given the option of proposing further transmission reinforcements at its expense or the retiring of older units to mitigate the congestion and losses.[68]

After considering these comments, we modify our recommendation. The preferred delivery point is as proposed by Delmarva. From a pricing standpoint, the seller, not Delmarva, would be responsible for marginal congestion and losses (positive or negative) from their point of connection compared to the Delmarva zone. However, generators would have the option to deliver to an interconnection point within the Delmarva zone and for Delmarva to take into consideration the risk of marginal losses and congestion in its bid evaluation, with the understanding that this would be evaluated both from the standpoint of price and price stability. If bidders choose the latter route and losses and congestion are critical to the result of the RFP, Delmarva should provide the bidder with the opportunity to reduce congestion and losses at its expense but only if there is adequate time in the evaluation process to accommodate the bidder. If Delmarva proposes a self-build project in the IRP process, the matter should be reviewed to determine that Delmarva is not exercising any undue preference.

E Output Contract

Under the Act, 26 Del. C. § 1007(d), Delmarva's "proposed RFP shall include a proposed form of output contract which shall include capacity and energy and may include ancillary electric products and environmental attributes between the electric distribution company and developers of new generation facilities, which contract shall have a term of no less than 10 years and no more than 25 years." The proposed RFP did not, however, include the proposed form of output contract. Delmarva's approach was to include as Attachment 1 to the proposed RFP a detailed Term Sheet, entitled "KEY COMMERCIAL TERMS OF POWER PURCHASE AGREEMENT" ("Term Sheet"). Delmarva proposes that the Term Sheet provides the "non-negotiable legal terms governing the purchase of energy and capacity."[69] Interested parties could register to receive a copy of the output contract or power purchase agreement ("PPA")one month before bids are due.

In its comments, NRG proposed that Delmarva provide the proposed form of contract to bidders as soon as possible. If the Delmarva approach were used, it is not clear to the Independent Consultant how the Commission or the staff could conduct the review mandated by 26 Del. C. § 1007(d)(1) prior to the submission of the standard contract.

As a result, we recommend that Delmarva be required to provide the proposed draft standard PPA for Commission review no later than November 1, 2006. We expect that the Commission should be in a position to direct Delmarva to issue the draft standard PPA with any modifications it may order by November 14, 2006. If the Commission, however, is not ready to rule on the issues that are addressed in the proposed term sheet at the Commission's scheduled meeting of

[68] NRG Comments on the Independent Consultant's Report at 13-15.
[69] RFP Section 2.4.2 (H), at 17.

October 17, 2006, Delmarva should be given up to ten business days to provide the draft standard PPA for Commission review from the date the substance of the Commission's ruling is conveyed to Delmarva.

F Regulatory Out Clause and Related Regulatory Issues

Delmarva has crafted a variety of provisions that deal with regulatory approvals and related regulatory issues. In Section 1.8, page 4, of the RFP and at page 16 of the Term Sheet, Delmarva created a condition precedent to the obligations of the parties under the PPA. That condition is the receipt by Delmarva of a non-appealable Regulatory Approval by June 30, 2007. Regulatory Approval in the Term Sheet and in the RFP is described as including (1) approval of the PPA terms without modification (or with only such modifications as are acceptable to the parties) by the DPSC, the Delaware Department of Natural Resources and Environmental Control ("DNREC") or any other regulatory agency which claims jurisdiction over the PPA; and (2) receipt of a final, non-appealable order of the DPSC allowing Delmarva to recover PPA payments "in utility revenue" subject only to DPSC review with respect to contract administration.

In the event that the Regulatory Approval of the PPA was not received by the deadline, Delmarva proposed that either party may terminate the PPA without liability or further obligation. Lastly, Delmarva proposed that at any time after the defined "Initial Delivery Date," if Delmarva were not permitted to recover all amounts payable under PPA, Delmarva may terminate the PPA without liability. At pages 23-24 of its comments, NRG points out that the latter unilateral right of the PPA Buyer to terminate, once initial approvals are obtained, would preclude financing and that as a result, such a "regulatory out" clause is unacceptable in the PPA. Bluewater Wind concurs with this NRG comment.

In standard long-term PPAs, initial conditions precedent for regulatory approval are commonplace. Deadlines are often imposed and the parties to the PPA understand that until the utility Buyer obtains its necessary regulatory approvals, significant commitment of capital to the Seller's development effort cannot be made. With this background, the Independent Consultant considers Delmarva's suggested condition precedent for Regulatory Approval to be conceptually acceptable. We have addressed this matter in our markup to the proposed Key Commercial Terms in the Proposed RFP.

With respect to the specific nature of the Regulatory Approval sought by Delmarva, we are of the view that it is fair and reasonable to provide Delmarva with an approval of entry into a PPA and appropriate assurances of cost recovery through a regulatory mechanism. In fact, the Act provides that if the Commission approves a contract as part of the IRP process, all reasonable incurred costs of the contracts shall be included in standard offer service rates.[70] However, we defer to the Commission's Rate Counsel regarding the particulars of the approval to be provided and the rate recovery mechanism.

[70] 26 Del. C. § 1007(b). Delmarva's reply comments (p. 19) ignore the statutory provisions and standard electric industry practice, where non-regulated sellers are not subject to a regulated utility's ability to recover costs in rates after initial approval for the PPA is obtained.

After Regulatory Approval, any subsequent "regulatory out," i.e., a unilateral right, without liability, for Delmarva either to terminate the PPA or to reduce PPA pricing to reflect any subsequent failure to recover PPA costs in revenues, would present insurmountable barriers to the financing of a project. Capital would not be made available for a project that might at any time during or after construction lose the power revenues supporting the capital investment. As a result, the Independent Consultant recommends that the "regulatory out" clause be deleted from the Key Commercial Terms and not be included in the standard form PPA.

In its comments, the Delaware Energy Users Group addressed related revenue recovery issues. This group takes the position that the cost of the IRP process, the related RFP process and any PPA should not be assigned either to distribution service rates or to hourly priced SOS service. In this regard, the group comments that the Commission should recognize that the PPA could lead to higher SOS prices, and that a nonbypassable charge should not be added to distribution rates in order to protect SOS customers, notwithstanding the fact that this could be allowed under 26 Del C. § 1010(c). That provision states:

> After hearing and a determination that it is in the public interest, the Commission is in the public interest, the Commission is authorized to restrict retail competition and/or add a nonbypassable charge to protect the customers of the electric distribution company receiving standard offer service. The General Assembly recognizes that electric distribution companies are now required to provide standard offer service to many customers who may not have the opportunity to choose their own electric supplier. Consequently, it is necessary to protect these customers from substantial migration away from standard offer service, whereupon they may be forced to share too great a share of the cost of the fixed assets that are necessary to serve them as required by [the Act].

Along with the potential benefit of a stable-priced PPA that hopefully will fall below the market price more often than not, there is always the potential for such a PPA to cause SOS prices to be above the market price at some point or points in time during the term of the PPA. In the Independent Consultant's view, little, if any, value would be gained if the Commission limited itself, now or in the future, from ever assessing nonbypassable charges to distribution customers on account of the PPA costs. In fact, to do otherwise, would subvert the purpose of the statutory "fallback mechanism" provided by Section 1010(c) of the Act. With respect to the position of the Delaware Energy Users Group that no related costs ever be assigned to hourly SOS customers, we defer to the Commission's Rate Counsel.

V Threshold Requirements

A Notice of Intent to Bid

One of the threshold requirements imposed by Delmarva is that each bidder must submit the required Notice of Intent to Bid by end of the day on November 22, 2006. Bidders are also required to provide the information required by Delmarva to undertake a transmission impact study on the Notice of Intent to Bid form. Delmarva's rationale for establishing submission of a Notice of Intent as a threshold criterion is based on the time frame for completing the evaluation process and the need to undertake the transmission study prior to receipt of bids.

While this threshold criterion is not common in other bidding processes, Delmarva's rationale is reasonable and justified.

B Credit Requirements

Delmarva has listed three credit requirements for bidders to meet to pass the credit threshold:

1. Each bidder must demonstrate that it has sufficient financial wherewithal to finance the project being proposed, including providing evidence of the bidder's credit rating, short-term debt rating, total net worth, financial statements, liquidity and financial stability.
2. The net worth of the bidder must be at least as large as the total capital that will be required for this project.
3. Bidders and/or guarantor must have an investment grade rating for senior unsecured debt or have equivalent financial standing.

Several prospective bidders have raised issues with regard to the threshold credit requirements. SCS Energy states that the net worth and investment grade requirements will effectively exclude bids by special purpose project entities. According to SCS, this also makes it highly unlikely that the proposed RFP will generate any bids for new or innovative baseload technology (e.g. coal gasification). Bluewater Wind argues that a requirement for an investment grade rating discriminates against smaller private companies and that the investment grade rating requirement is stringent and expensive for a project-based bid. Bluewater also states that it may be more advantageous to Delmarva to consider non-investment grade rated sellers with a project finance structure where a second lien is provided as collateral to the buyer, there are no other outside obligations of the seller, or the project maintains a higher equity ratio. NRG recommends the inclusion of objective criteria in the RFP which demonstrate the ability of the applicable sponsoring entity to obtain financing in order to provide some hurdle to participation and discourage bids which are simply not credible, while limiting the review of credit criteria only in connection with an evaluation of the proposed project level entity for all bids. There is no evidence, according to NRG, that contracting with a project level entity will expose customers to additional risks of default on the PPA or a bankruptcy of the entity.

Credit issues have become some of the most contentious issues in competitive bidding processes. Utility credit departments, in many cases, apply the same credit threshold requirements to long-term arrangements backed by specific assets as they do to power trading arrangements. Power project developers argue that these requirements are not applicable for traditional project financed entities proposed as special purpose entities since there is generally a hard asset underlying their contractual obligations. The conflict is evident in this case based on Delmarva's initial threshold requirements and the comments of several prospective bidders.

In that regard, the combined threshold requirement such as that proposed by Delmarva (i.e. bidders or their guarantors must possess an investment grade rating and bidders must meet a specified net worth threshold) is not common in the industry. While some RFPs require bidders or their guarantor to possess an investment grade rating to compete, many processes allow non-investment grade entities to compete but require that such entities satisfy contractual security requirements solely through letters of credit or cash collateral. In contrast, a bidder with an investment grade parent can provide all or most of the required contractual security (credit support) through a parent guarantee. An approach applied in several bidding processes is for the purchasing utility to require the bidders to demonstrate that they will be able to meet the contractual security (credit assurance) requirements if they are awarded a contract. Moreover, under Delmarva's proposal, it appears that the bidder, and not just the bidder's guarantor (almost always a parent or affiliated company), must itself meet the net worth requirement, which is not the way project development companies usually structure entities that own power plant projects.

Based on the experience of the Independent Consultant and the comments of the bidders, the threshold credit requirements proposed by Delmarva would likely be too stringent to encourage robust competition and would likely limit the number of eligible bidders. Instead of requiring bidders to meet all three requirements listed, we recommend that bidders should be able to satisfy the credit threshold requirement by either:

(a) satisfying Delmarva's proposed requirements, or

(b) (i) providing a reasonable showing of their ability to finance their project based on past experience and a sound financial plan identifying the proposed sources for debt and equity, which also includes a letter from a financial institution indicating the project is financeable, and
(ii) demonstrating its ability (and/or that of its credit support provider) to provide the required security, including its plan for doing so (including type of security, sources of security, and a description of its credit support provider).

The Independent Consultant recommends that the Commission and Energy Office encourage competition at the front end of the process by not imposing such stringent requirements that only a limited number of bidders would be eligible to meet.

In its comments on the Independent Consultant's initial report, Delmarva opposes any significant changes to these provisions. Delmarva states that it is crucial that the bidder or guarantor have an investment grade rating, asserting that the default rate for non-investment grade companies is over ten times higher than that of investment grade companies, its current credit rating and size reduces its flexibility to take on such a significant additional risk, and a non-investment grade supplier, especially when supplying a major portion of the load over the long-term, would markedly increase Delmarva Power's counterparty risk, and put downward pressure on Delmarva Power's bond rating.[71] Delmarva Power contends that limiting participation to investment grade bidders is a necessary and cost-effective way of controlling the strongly adverse financial impact of a supplier default on Delmarva Power's customers. Delmarva also

[71] Comments at 20-21.

attempted to clarify the net worth threshold requirement and believes the net worth threshold requirement proposed in its RFP would further reduce the probability of a supplier default and in turn reduce the risk to its customers.

As we noted above, credit issues remain among the most contentious issues in competitive bidding processes. While some utilities require that the bidder or its credit support provider maintain an investment grade rating to submit a bid, many other processes are not as restrictive and instead place more reliance on the level of security to be provided by non-investment grade entities (as well as all bidders). As such, resolution of this issue requires a careful balancing of interests. We believe that the better approach in the context of this RFP is to rely on the level of security, but as a threshold matter, require that the bidder demonstrate an ability to provide the security. As we discuss in Section IV.F of this report, we support security requirements that are in the higher range of what is commercially reasonable, giving due consideration, among other things, to Delmarva's size and credit rating. Moreover, taking Delmarva's concerns into consideration, we propose to modify the Exposure category to explicitly take into consideration in the bid evaluation a party's credit rating (see Section VI.C.ix). We agree with Delmarva that an investment grade counterparty is substantially more desirable than a counterparty that is not, other things being equal.

However, we believe that these issues should be understood in a broader context—that counterparties are likely to be project companies, not energy marketing companies, the contracts will be unit contingent contracts for new generation (if our recommendations are adopted), not firm system sales, and any contracts entered into will be at the directive of state agencies pursuant to legislation that provides a regulatory mechanism for Delmarva to recover costs approved by the state agencies. Default rates of project companies with unit contracts under long-term PPAs are relatively small once projects are in construction or operation (default rates of company bonds that are below investment grade are not representative of default rates of project financings). Project development failure is much higher (due to permitting and other risks). Given the statutory scheme and the use of the PPA as a price stabilization mechanism, it is highly unlikely that Delmarva's shareholders or bondholders would be at risk for a project failure at the development stage. While the long-term price stability benefits that would not be effective for many years into the future might be lost, there would be no near-term cost to be incurred. In fact, Delmarva would draw down the development security letter of credit and the funds would presumably accrue to the benefit of Delmarva SOS customers (which would offset the loss of the long-term price stabilization contract).

If there is a default while the project is in operation, Delmarva would be protected both by an operational period letter of credit (which would certainly be the case if the counterparty is not investment grade) and the company would also be protected by a secured second lien on the project. And unlike a competitive energy supplier, Delmarva would have the ability to seek regulatory relief if its dual position as a secured party (letter of credit and second lien) turned out to be inadequate in terms of cost recovery. As discussed in the section of this report on Imputed Debt Offset (Section VI.C.viii), the rating agencies do incorporate consideration of a number of factors in their analysis, including regulatory recovery mechanisms.

C Variable Interest Entity Treatment

As a threshold requirement, Delmarva states that it is unwilling to be subject to accounting and tax treatment that results from Variable Interest Entity ("VIE") treatment as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 (FIN 46), as revised. Delmarva indicates that all proposals will be assessed for appropriate accounting and/or tax treatment. If a proposal is deemed to be a variable interest entity it will be consolidated on the utility's balance sheet, which will impact the utility's financial statements. Delmarva would have to carry the entity on its books without control over the entity's operation (except through contract). The primary objective of FIN 46 is to provide guidance on the identification of, and financial reporting for, entities over which control was achieved through means other than voting rights. Bidders are required to supply Delmarva with all the information necessary to make such assessments, with such information including: data supporting the economic life of the unit, the fair market value, executory costs, non-executory costs, investment tax credits and other costs (including debt specific to the asset being proposed) associated with the proposal.

In its 2005 RFP, Puget Sound Energy noted that entities proposing power purchase agreements, power bridging agreements, or tolling agreements may fall under the consolidation requirements of FIN 46, depending upon the power purchase term and the organizational structure of the responding entity. The RFP outlined the information Puget Sound Energy required of bidders to make a determination of the applicability of FIN 46. Hawaiian Electric Company ("HECO") included a detailed description of the consolidation accounting issue in Exhibit C to its Statement of Position in Docket No. 03-0372, Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii, March 2005, including the type of information required to make the assessment and a brief assessment of whether the independent power projects under contract to HECO require VIE treatment.

Only two prospective bidders addressed this issue. Bluewater Wind concurred with Delmarva's position regarding VIE treatment. NRG states that clarification is needed as to what information bidders must submit pursuant to Delmarva's assessment of proposals for accounting and/or tax treatment. The current description of the information that will be required in the Proposed RFP is too vague. Moreover, NRG questions the relevance in the RFP process of an inquiry into a bidder's tax treatment regarding its investment. This inquiry into a RFP bidder's tax status should be eliminated, unless Delmarva can demonstrate a compelling reason why this information is necessary.

While it is common practice in competitive bidding processes for utilities to take a similar position to Delmarva regarding VIE treatment, one of the key issues is the information basis on which the purchasing utility will determine whether a particular proposal will trigger VIE treatment. Unfortunately, the basis for determining whether a specific project entity or structure triggers FIN 46 is murky at best. While at least several major accounting firms have issued opinions on FIN 46, it appears that the determination of whether a proposal triggers FIN 46 will depend on the specific structure of each entity and the nature of the power contract. The Independent Consultant is concerned that if Delmarva is to decide whether a particular proposal triggers FIN 46, then Delmarva should clearly identify the information it requires to make such a determination and the methodology it will use to assess if a specific proposal meets the threshold requirements. As a result, it is our opinion that Delmarva has the right to include VIE treatment as a threshold requirement in the RFP, but we recommend that the Company should provide more clarity regarding the information it requires and the standards it will use to assess each proposal. Moreover, in the event of an adverse decision by Delmarva with respect to a particular bid, the Independent Consultant recommends that Delmarva be required to provide a written justification in a timely fashion to the Independent Consultant and the State Agencies so such a determination could be adequately reviewed.

While SCS Energy recognizes that the implications of FIN 46 and the balance sheet impact of the PPA are legitimate issues for Delmarva Power in both its initial and reply comments, SCS Energy states that they are highly sensitive to the structure of the PPA and the underlying regulatory context. SCS Energy states that FIN 46 issues should not be addressed in the scoring or evaluation of the RFP. Instead, the RFP should simply advise bidders that upon selection of a favored bidder, the FIN 46 and VIE issues may need to be resolved among the Commission, the bidder, and Delmarva Power in determining whether and on what basis to proceed to a contract award once a preferred bidder has been selected.

It has been the experience of the Independent Consultant that attempting to resolve this issue at the time of contract negotiations could lead to a protracted negotiation process. We believe it is preferable to resolve this issue at the front end of the process rather than proceeding to contract negotiation only to find that the negotiation process could be derailed or delayed while this issue is addressed. If necessary, Delmarva could request follow-up information from a bidder to determine whether or not its proposal will trigger VIE treatment well in advance of contract negotiations. Given the relatively short timeframe for the bidding process, such an approach should make more efficient use of time.

D Site Control

As a proposed threshold requirement, Delmarva would require each bidder to "demonstrate that it has identified a site for capacity, and, if not owned by the bidder at time of Proposal submittal" to "demonstrate its ability to acquire or secure use of the site by holding a purchase option or a binding letter of intent from the site owner(s)."

Bluewater Wind commented that, for off-shore wind projects, this requirement should be treated as satisfied if the bidder can (a) demonstrate the feasibility of obtaining permits and licenses, and (b) provide copies of requests from the bidder to agencies beginning the permitting of specific off-shore sites. Delmarva asserts that this standard is inadequate and requests that a more stringent standard be proposed by Bluewater or the Independent Consultant.[72]

Pursuant to the Energy Policy Act of 2005, rules for acquiring control of off-shore wind sites are still being developed by the Minerals Management Service. At this time, it is not entirely clear what a developer of an off-shore project will be able to provide regarding site control as part of

[72] Comments on the Independent Consultant's Report at 21-22.

this RFP process. Accordingly, the Independent Consultant recommends accepting the proposal from Bluewater as a reasonable way to determine whether an off-shore wind project has reached a sufficient level of development to be considered on its merits. In addition, while we agree that other projects should provide binding letters of intent (at a minimum), the bidder should be offered a short cure period if clarification of rights under such a letter of intent is needed.

E Permitting Schedule and Engineering Study

The Proposed RFP also establishes as a threshold requirement the submission by the bidder of "a reasonable schedule for acquisition of all necessary permits." In addition, the bidder must "demonstrate its ability to comply with all applicable environmental laws and regulations."

No one commented on this requirement and the Independent Consultant agrees that this is reasonable. We recommend that the schedule include not only the permits but also a complete development and construction schedule.

F Security Requirements

i. Pre-operational Period

As the Development Period Security, Delmarva proposes that the Seller provide a Letter of Credit on the Execution Date for $50/kW of contract capacity. Fifteen days after the Effective Date, i.e., after all conditions precedent to the Effective Date, including the occurrence of Regulatory Approval, Delmarva requires that security be increased to $100/kW. However, the potential exposure of the PPA Seller exceeds $100/kW before the Initial Delivery Date since Delay Damages, as discussed below and at Section VII.b below, may become due during the pre-operational period.

Delay Damages become due as they accrue and if not paid as due, such damages may be withdrawn from the $100/kW security. Upon withdrawal, Delmarva proposes that full replenishment of the security back to $100/kW is required.[73] Therefore, the maximum pre-operational security requirement is $100/kW plus the maximum amount of Delay Damages, which appears to be $85.15/kW ($0.2333 per kW-day for one year).[74]. Delmarva has also proposed that, whenever there is an overlap in the construction period and the expected delivery period, the PPA Seller would be required to maintain both Development Period Security and also to post Operational Period Security.[75] While the delay damages proposed by Delmarva appear to be higher than in other RFPs, daily delay damages in the $0.17 to $0.20/kW range have been observed.[76] In response to these security requirements, Bluewater Wind comments that such requirements are too high and indicates that for renewable projects, security has been in the range of $30-60/kW in other procurements.

[73] RFP Section 3.4.1.4 at 21.
[74] Key Commercial Terms at 6.
[75] RFP Section 3.4.1.4 at 21.
[76] Duke Power's 1995 RFP had daily delay damages of $0.17/kW in 1995 dollars.

With respect to the proposed amount of $100/kW, our analysis of other recent RFPs indicates that the development period security of $100/kW is reasonable. We have observed a range of security levels from $50/kW up to $200/kW.[77] In some cases, the development period security secures the maximum amount of potential delay damages; in other cases, such as in Delmarva's Proposed RFP, additional delay damage security is due upon the occurrence of delays (and if not paid, part of the development period security is taken by the Buyer and the Seller must replenish it). The level and structure of the security proposed by Delmarva falls within a reasonable range.

However, we recommend several modifications and limitations to the proposed development period security. First, delay damages and damages for failure to meet and pre-Initial Delivery Date milestones should not exceed $85/kW. Second, due to lower capacity factors and to the generally lower required security in the industry, we recommend that wind projects pay only 40% of the normal required security for baseload and other projects (i.e., $40/kW per kW of nameplate capacity as compared to $100/kW for development period security), 40% of the associated Delay Damages, and 40% of our proposed cap on operational period security (see Section V.vi.b below). Finally, in the event of delays that cause the planned development period to extend beyond the Guaranteed Initial Delivery Date, there should be no doubling up on security. The Independent Consultant recommends that operational period security should only be applicable once the Initial Delivery Date has actually occurred.

Delmarva has several concerns about our proposed modifications to Delmarva's proposed development period security requirements. Delmarva claims that we have recommended that a bidder, at least with an investment grade guarantor, could provide a parent guaranty instead of a letter of credit to provide the requisite credit support and that this would weaken the credit and security arrangements.[78] While we did not intend to propose a modification to this aspect of Delmarva's development period security package, we appreciate that our mark up to Section 3.4.2 of the RFP, which we construed as applying simply to operational period security conveyed a misimpression. We accept Delmarva's proposal that the required form of security for developmental period security should be letters of credit or other security acceptable to Delmarva.[79]

Delmarva objects to our proposed differentiated treatment for security for wind projects, arguing that it is discriminatory and could result in projects claiming lower capacity factors to reduce

[77] As an example, in its 2003 RFP, Progress Energy's development security increases to $50/kW during the development period of the project. XCEL Energy's 2005 RFP included security requirements of $125/kW, while Georgia Power Company's 2006 RFP required development security of $120/kW. Southwestern Electric Power Company's 2005 RFP required security in excess of $200/kW for baseload resources for the lowest credit rated entities.

[78] Comments on the Independent Consultant's Report at 3.

[79] We propose that the second sentence of Section 3.4.2 of the RFP be modified to include the capitalized language: "An irrevocable standby letter of credit ("Letter of Credit") in form and substance acceptable to Delmarva, from an Issuer with a senior unsecured long-term credit rating (un-enhanced by third-party support) equivalent to A- or better as determined by both Standard & Poor's or the equivalent by Moody's or Fitch is REQUIRED FOR DEVELOPMENT PERIOD SECURITY AND IS the preferred form of security FOR OPERATIONAL PERIOD SECURITY. Subject to other restrictions described herein, Delmarva will accept a guarantee from an investment grade rated entity FOR OPERATIONAL PERIOD SECURITY."

their security requirements. Initially, we would like to clarify that our proposed treatment that wind projects would be required to post 40% of the security conventional projects would be required to post (based on nameplate capacity) would also apply to other intermittent renewable energy projects, such as hydro and solar. Second, this level of security is not discriminatory. It is based on the different characteristics of these types of projects: (a) lower levels of energy produced by these types of projects (generally, less than a 40% capacity factor), (b) lower levels of UCAP (initially, 20% of nameplate capacity for wind under current PJM rules), and (c) market levels for security for these types of projects are lower than conventional projects. Finally, since the amount of security would be based on a percentage of nameplate capacity, there will be no incentive to lower the capacity factor that they say their projects can provide.

Delmarva states that it did not intend to require a "doubling up" of security payments, stating that the operational security does not commence until the plant comes on line and delay payments would cease concurrent with the plant operating. We have addressed this question by our markup to Section 3.4.15 of the RFP.

Finally, Delmarva takes exception to the Independent Consultant's recommendation that delay damages and pre-completion milestone damages should not exceed $85/kW. It has been clarified to us that the only pre-commercial operation milestone date liquidated damages (other than those associated with the right to terminate the PPA) pertain to the permitting milestone date (i.e., there are no other interim milestones that if missed would result in the equivalent of delay damages). With this understanding, we withdraw this recommendation.[80]

SCS Energy contends that $100/kW is an excessive and onerous amount of security.[81] However, as indicated above, experience with other RFPs in the industry supports this level of security as being within the range of commercial reasonableness.

ii. Operational Period

As a threshold matter, Delmarva takes the position that the PPA Buyer should not be required to post security even in the event of a downgrade.[82] While the Independent Consultant recognizes that, in the event Delmarva's credit rating were downgraded, the PPA Seller may have difficulty financing its project, it is not recommended here that Delmarva be required to post credit support in the event of such a downgrade. A credit support requirement would only increase Delmarva's, and ultimately ratepayers' PPA costs and would put additional pressure on Delmarva's credit rating. It is relatively common in utility power procurements that the buyer, if it is currently investment grade rated, not have the obligation to provide credit support in the event of a downgrade.

[80] Under Delmarva's Proposed RFP (sections 3.41.1 and 3.4.2), security of $100/kW would be posted by Seller soon after the contract's effective date, with delay damages assessed as incurred; we note that Delmarva's proposed term sheet also required an additional posting of one year of delay damages--$85/kW--soon after the effective date for a total of $185/kW, but this is inconsistent with the Instruction to Bidders, guidance from Delmarva's RFP manager, and the lack of any written comment on this point by Delmarva on our draft report or mark up to the RFP.
[81] Reply Comments at 3.
[82] RFP Section 2.2.2 at 8.

With respect to the Seller's operational period security, or the Seller's Collateral Requirement, Delmarva has proposed two years of replacement power costs calculated as the expected PJM RPM capacity value (or a mutually agreed upon equivalent) **plus** NYMEX Henry Hub forward energy price * 8,000 btu/kWh.[83] Delmarva reserves the right to change the heat rate, subject to the nature of the PPA. In Delmarva's formulation, the Collateral Requirement would not be subject to any maximum limitation or "cap."

Delmarva proposes that at least ten percent of the required security would be in the form of a Letter of Credit.[84] Based on the credit rating and a specified percentage of the total net worth of the PPA Seller or its guarantor, a portion of the requirement could be unsecured.[85] The remainder must be in the form of a Letter of Credit. In the case of a downgrade event affecting the PPA Seller or its guarantor, Delmarva intends that the credit requirements would be re-evaluated in accordance with overall formulae. In addition to the foregoing security, Delmarva will require that the PPA Seller grant the PPA Buyer a lien on the Project, subordinate to the project lender.[86]

In response to these Delmarva positions, NRG and SCS emphasize that operating security should be based on the normal cover theory of damages, i.e., the difference between the proxy price for replacement power and the contract price. Bluewater Wind again takes the position that the security requirement is excessive and calls for a lower requirement for wind projects. Bluewater recommends that a second lien, in lieu of a Letter of Credit, be used or that unsecured credit be exclusively relied upon and that, in any event, there be a cap on required security. The Public Advocate also recommends that the security requirements should be lessened to be more conventional.

In the Independent Consultant's experience, proxy formulae for the replacement cost of power in determining Operational Security are not unusual. The Independent Consultant finds the Delmarva proxy unobjectionable; however, the conventional theory of cover damages should apply. As a result, the formula would calculate net replacement costs as the positive difference between the proxy market price and the PPA contract price. It is in fact the Independent Consultant's understanding that this is what was actually intended by Delmarva.

However, the proposed formula does not contain any limitation on the maximum amount of security. A "cap" on the amount of Operational Security is recommended here to prevent the operation of the formula from reaching burdensome amounts. Based on our review of other recent RFPs, we believe a cap of $200/kW is reasonable.[87] A seller with an investment grade parent could provide a parent guarantee capped at the $200/kW level once the Initial Delivery Date of its plant has been achieved. The amount of liquid collateral that would be required would be pursuant to Delmarva's credit formulas. A seller without an investment grade

[83] RFP Section 3.4.14 at 20.
[84] See RFP Section 3.4.4 at 22.
[85] RFP Section 3.4.3 at 22.
[86] Term Sheet at 14.
[87] Entergy's 2006 RFP had a cap of $20,000,000 per 100 MW bid or $200/kW for solid fuel projects and $100/kW for gas-fired combined cycles.

guarantor would be required to post the full $200/kW in the form of a letter of credit or other credit support acceptable to the Buyer.

In its mark up to the term sheet (p. 5), Bluewater Wind argues that a second lien should be in lieu of a letter of credit for operational period security, not in addition to it, that the $200/kW cap on operational period security is excessive and should be reduced to $100/kW, and that Delmarva should be required to put up a letter of credit. Initially, we note that wind and other intermittent renewable energy projects would only be required to provide operational period security of $80/kW, which we believe is commercially reasonable in the context of this RFP. While, we believe a second lien can provide valuable security for a utility buyer, it should be viewed as supplemental security, not primary security. Finally, we do not believe requiring Delmarva to post a letter of credit is necessary for project developers and would impose additional costs on Delmarva and perhaps its customers.

We would like to make an additional clarification and modification to our proposal on operational security. The $200/kW cap we proposed does not include the value of the subordinated lien on the plant. The $200/kW cap might not be sufficient to cover damages over a two-year period if market prices are considerably higher than the contract price (over $16.50/MWh more for a 70% capacity factor project). In that circumstance, a second lien would likely have considerable value (assuming that the plant does not have major operational problems) because high power prices would make the plant more valuable. In order to assure that a substantial portion of this value would be accessible to Delmarva but not in a manner that would likely have an adverse effect on generators, the Independent Consultant supports a provision that limits a seller's ability to leverage the project by more than 70% with lenders that have senior security interests.

G Term Sheet

As a threshold requirement, Delmarva proposes that bidders must agree with the term sheet provided in the Proposed RFP, which Delmarva states contains "terms and conditions that Delmarva considers to be non-negotiable."[88] Initially, we have concerns regarding the fairness and appropriateness of some of the proposed contract terms. These matters are addressed in Part VII of this report. However, even with modification to the proposed terms and conditions, we do not agree that failure to agree to any term or condition in any manner should be the basis for failure to meet a threshold requirement. In our initial report, we proposed that, contract exceptions proposed by a bidder would only result in a determination that a threshold requirement has not been satisfied if Delmarva and the Independent Consultant agree that a bidder's contract exceptions taken as a whole effect a fundamental restructuring of the risk allocation set forth in the RFP, are unacceptable, and the bidder, upon being informed of that assessment, fails to withdraw the pertinent exceptions.

Delmarva argues that the "fundamental restructuring of the risk allocation" standard is too high a bar and would be difficult to administer.[89] To an extent, we agree. The key commercial terms in

[88] RFP Section 2.2.2 at 8.
[89] Comments on the Independent Consultant's Report at 33.

the term sheet—such as the level and form of required security and liquidated damages—should be non-negotiable if there is a reasonable degree of comfort that they are commercially reasonable for generators. We feel comfortable that the terms we are proposing are commercially reasonable and would support their being "non-negotiable" in the RFP. We do not have the same level of comfort with aspects of Delmarva's, particularly the lack of a cap on the operational period security. We would not make that item "non-negotiable." Moreover, we do not agree that any proposed changes to language in the term sheet should necessarily result in a determination that a bidder has failed to satisfy a threshold requirement.

VI Bid Evaluation Methodology

A Scoring Methodology and its Use

Delmarva proposes a methodology whereby each project is scored in accordance with various categories (or sub-categories) of price and non-price factors, and the total price and non-price points are tabulated and then combined to form a single score. According to the Proposed RFP, the bid that receives the highest number of points is the winning bid, which Delmarva would then plug into its IRP evaluation. In the following section, we will address each of the price and non-price factor evaluation categories and their relative weighting. Before doing that, the Independent Consultant wishes to provide an overview of the scoring methodology and to recommend a framework for using the scoring methodology from a decisional perspective.

Delmarva proposed 60 points for price factor (of which 20 points are for price stability), with 40 points for non-price factors, including environmental considerations, fuel diversity, technology innovativeness and reliability, and proposed changes to a standard form power purchase agreement. Other parties have argued that the weights should be substantially shifted between the various categories, but no one has conceptually opposed a bid evaluation system that results in a single score that will determine the "winner."

The weighting of scoring categories in an RFP is always a challenge as each RFP usually has a number of objectives. This observation is true here, where in our view, there are three sets of considerations that underlie the desire to seek a long-term power purchase contract from new in-state generation. First, there is the desire to provide Delaware residential and small commercial customers with the opportunity to stabilize their rates at attractive or acceptable levels and on attractive or reasonable terms and conditions (price, price stability and contract terms). Second, there is the desire to support power generation projects that will provide benefits (or mitigate impacts) to the state overall and diversification for Delmarva's SOS customers (environmental impacts, fuel diversity, technology innovation). Finally, as in any other RFP for new generation, there is the desire to contract for a project that has a high likelihood of being built and thereby providing the foregoing economic and environmental benefits (financing plan, site development, operation date certainty, reliability, bidder experience).

While we believe that the project that receives the highest combined score could be the "best" project, this may not necessarily be the case, regardless of how points are allocated among specific categories. We believe that a project should score well or at least acceptably in each of the three "super categories" outlined in the preceding paragraph—Economics, Favorable Characteristics, and Viability. Since the ultimate decision will be made by the State Agencies based on the criteria set forth in the RFP in accordance with the Act, and the simple addition of scores for those criteria may not fully capture the best option, we believe that there should be some judgment allowed. Hence, we recommend evaluating the bids both on an overall score basis and with respect to the component score in each of the three "super categories."[90] By using these multiple perspectives, the State Agencies can examine each project in a more comprehensive fashion in carrying out their obligations under the Act.

Delmarva objects to the use of "super categories," arguing that it represents a second level of threshold criteria and that it injects too much subjectivity into the process.[91] We do not agree that the ability of the State Agencies to evaluate the bids based on how they score within the super categories as well as their total scores represents a second level of threshold categories. There are no "minimum scores" required in each super category, per se. Point scoring systems, including the ones recommended by Delmarva and the Independent Consultant, are not infallibly precise and with four state agencies making determinations based on complex analyses and considerations, it is reasonable to allow the exercise of some judgment within the context of a highly structured point scoring system. The super category approach simply provides a rational way of ordering the various price and non-price factors to be utilized in the analysis and should assist Delmarva and the Independent Consultant in putting together their evaluations and recommendations and the State Agencies in their decision making process.

B Delmarva Affiliate Issues

The RFP states or suggest that Delmarva and/or an affiliate of Delmarva may submit proposals, which will be evaluated under the same evaluation process as all other proposals and shall not receive any favorable treatment.[92] Under the Act, an affiliate of Delmarva may bid in the RFP process.[93] Delmarva itself may propose a self-build project in the IRP process,[94] which could presumably be compared to a bid proposed pursuant to the RFP.

The ability of Delmarva and/or an affiliate to bid or propose alternative projects raises traditional concerns over self-dealing and fairness issues in the bid evaluation process. From a bid evaluation process standpoint, it is preferable that Delmarva bid through an affiliate (as it must in the RFP process) since the affiliate bid would be on a more equal footing with third-party bidders. However, even under these circumstances, self-dealing issues will remain.

[90] For example, a project that received an overall score of 76, with an Economic score of 50, a Favorable Characteristics score of 16 and a Viability Score of 10, would be evaluated both from the standpoint of its overall score and also with respect to its score in each of the "super categories." The score in each of the super categories, in turn, would be the sum of each of its component category scores. For example, a score of 10 for the Viability super category would be the sum of the scores in the financing plan (e.g. 3), site development (1), operation date certainty (2), reliability (1) and bidder experience (3) categories.

[91] Comments on the Independent Consultant's Report at 23.

[92] See RFP Section 6.2 at 27.

[93] 26 Del C. § 1007(d)(2).

[94] 26 Del C. § 1007(b)(3).

To allay any concerns over the potential for self-dealing concerns, the Independent Consultant proposed in our initial report that the following procedures should be implemented:

1. A proposal submitted by a Delmarva affiliate should be submitted to Delmarva and the Commission at the same time. Such a bid should be submitted one day in advance of the deadline for all other bids.

2. While the Proposed RFP correctly prohibits members of the RFP Evaluation Team from working on any affiliate proposals or a self-build proposal or communicating with members of the Company's self-build team or an affiliate's proposal team,[95] there should be a similar prohibition applicable to communications flowing in the other direction and to personnel working on an affiliate proposal or Company self-build proposal working on the RFP or RFP bid evaluation.

3. All the requirements of the RFP, including security, shall apply to any affiliate of Delmarva that submits a bid in response to the RFP in addition to those that apply specifically to Delmarva affiliates.

Delmarva requests a further explanation for the basis for our recommendation that any bid submitted by a Delmarva affiliate be submitted a day in advance of the deadline for all bids. Moreover, in light of the period of time that bidders may submit bids, Delmarva recommended naming December 21, 2006 as the day by which an affiliate bid must be submitted (the day before the December 22nd deadline). The day-in-advance requirement is a mechanism, used in other procurements, to minimize concerns that other bidders may have about self-dealing. December 21st is an acceptable deadline for a Delmarva affiliate bid. Bidders that are concerned about this issue would have the option to submit their bid before or after this date.

C Price Evaluation Methodology

The price factor evaluation in the Proposed RFP encompasses 60 points (out of a possible 100 points) with 40 points allocated to pricing rank (i.e. lowest expected price) and 20 points allocated to price stability. The price stability component is captured in the uncertainty component of the PPA Energy Price, Residual Standard Offer Service Cost, and the Loss under Probability of Default. While the RFP generally outlines the cost components of the evaluation, there is little information provided in the Proposed RFP about the methodology and models used. Delmarva and their consultant, ICF, have developed a process and methodology to evaluate the proposals received with certain elements of the evaluation process still undergoing review. For example, there is little information included in the RFP about the calculation of the price stability component and it is apparent based upon discussions with Delmarva and ICF that the methodology has not been highly defined or refined.

As described by Delmarva and ICF, the economic analysis will be undertaken as a multi-step process. The initial steps of the process will include the impact of the bid price on the Standard Offer (SOS) customers. This includes the direct evaluation of the contract price as well as an

[95] RFP Section 6.2 at 27.

indirect analysis that the generating unit should have an on the overall market price for power in Delaware. In addition, Delmarva proposes to include in the evaluation other cost factors such as the impact on transmission costs and losses associated with the generation option, an imputed debt offset, and a potential loss component based on an assessment of the probability of default. Bids will also be evaluated for the risks they place on customer costs based on an assessment of the level of price stability associated with the bid pricing structure. Finally, the top bid or combination of bids will be evaluated in the framework of the IRP to ensure a full consideration of costs has been addressed.

This section of the report will therefore discuss the proposed price factor evaluation process and the conceptual intent of the evaluation. Following will be a discussion of the modeling methodology to be used and the application of the models underlying the methodology. Last, will be a series of recommendations regarding the pricing methodology.

i. Point Allocation

As noted, Delmarva intends to allocate price factor points into two categories: pricing level or rank and price stability. Pricing overall will receive 60% of the total weight and non-price will be allocated 40%. Within the price-related factors, price rank or level will be allocated 40% of total weight and price stability 20%.

Several of the commenters raise concerns about the pricing point allocation. For example, SCS Energy states that the scoring and evaluation approach should be revised to allocate points equally among the criteria set forth in the Act. As a result, SCS Energy concludes that no points should be allocated to price rank and 20% of the points should be allocated to price stability. Bluewater Wind maintains a similar position. Bluewater states that lowest price should not unto itself be a selection criterion in the RFP because the Act simply does not stipulate “lowest cost,” per se, as a criterion in the selection process. As we indicated in Part III of this report, we believe that under the Act both price stability and the level of pricing are important together with the other factors addressed in the Act.

It is important to note that the common industry practice with regard to price and non-price weightings is generally within the range of 50% to 70% price and 30% to 50% non-price. A 60%/40% price/non-price weighting is typical as the basis for selecting a short-list. In most cases, lowest price is the primary selection criteria with risk factors included in the final evaluation in some processes. In some RFP processes where price stability is included, it is generally included as a non-price factor rather than as a price factor.

For this RFP, we believe that the 60% price/40% non-price weighting is reasonable and we recommend that it be used, subject to the “super category” evaluation approach to the evaluation outlined previously. In our initial report, we recommended a split within the the price category as follows:

Price	38
Price Stability	15
Exposure	5 (new category, aspects included by Delmarva in price stability)

Contract terms 2

The reduction in the price scoreallowed some additional points to be available for non-price factors, enabling us to provide additional weighting to environmental considerations.[96]

Some parties—including Bluewater Wind and Messrs. Firestone and Kempton—objected to the reduction of points for price stability absolutely and in relation to points for price. Delmarva objected to our proposed elimination of its proposed loss under probability of default evaluation criterion, which would consider bidder credit rating in price and price stability evaluation, and has questioned our treatment of contract terms as a price factor. We have considered these comments and would like to propose several modifications to our recommendations in this area:

- Price stability—increase of 5 points from 15 to 20
- Price—decrease of 5 points from 38 to 33
- Exposure—increase of 1 point from 5 to 6; bidder creditworthiness to be considered in the analysis
- Contract terms—decrease of 1 point from 2 to 1

We believe that these adjustments will provide a better balance in the point scoring system.

ii. Components of Price Factor Evaluation

Delmarva intends to evaluate all proposals based on price and operational performance factors in the Price Evaluation through simulation of the impact of the proposal on the costs paid by Delmarva's SOS customers. The price factor evaluation will include several cost components including the following:

- PPA Capacity Price
- PPA Energy Price
- Residual SOS Cost Impact
- T&D Project Impact
- Transmission Losses
- Imputed Debt Offset
- Loss under Probability of Default

Delmarva indicates in the RFP that it expects to calculate a levelized cost per kWh as the basis for calculating the cost of each bid. In addition, Delmarva will calculate the dollar magnitude of risk for SOS customers. Price stability will be captured in the uncertainty component of the PPA Energy Price, Residual SOS Cost and the Loss under Probability of Default. Delmarva is considering conducting a standard deviation assessment for estimating the stability of each bid.

[96] See Section VI.D for our assessment and recommendations on the weight to be accorded environmental considerations and other non-price factors.

iii. PPA Capacity Price

Delmarva indicates that bidders shall provide a levelized capacity price in dollars per kilowatt-month ($/kW-month). Variable capacity payments shall not be acceptable. Capacity may be provided only from the bidders' project and must be reliable as determined by whether it qualifies for UCAP in PJM. All project bids will be evaluated at the target equivalent availability specified by the bidder (or a substitute one if the specified EAF is deemed unrealistic).

The Independent Consultant is concerned about the requirement in the RFP for bidders to bid a fixed levelized capacity price; portions of the capacity price may not be indexed to general indices of inflation or to indices of specific capital cost components, such as steel. Many RFPs for long-term unit contingent power allow a portion of capacity prices allocable to fixed operations and maintenance costs to be indexed to a general inflation index, a labor cost index or both. Typically, capacity pricing has not allowed for indexing to capital cost components, such as the cost of steel. While this approach has been the general rule in previous RFP processes where gas-fired combined cycle projects have been predominant, there is a rationale for allowing longer lead time, capital intensive technologies such a coal-fired projects and offshore wind projects to allow some significant indexation in bid capacity prices. In past few years, the cost of steel, labor, and specialized metallurgical components have increased dramatically in price, leading to difficulties in securing an Engineering, Procurement and Construction (EPC) contract for such resources. The price risk generally leads to such projects bidding a higher fixed capacity cost to address such risk. If some of this price risk is mitigated through indexed pricing, a bidder could be more aggressive with its pricing. Some utilities have begun to address this issue by allowing bidders the option of either bidding a fixed capacity price or allowing the bidder to index the variable portions of its capacity cost by known indices that match the cost components. For example, the utility may allow the bidder to index components of the capacity price from the base period to either the time of execution of the EPC contract or to the in-service date of the project. Components of the bid tied to steel prices could be indexed to a steel index, while other components may be indexed to an inflation index.

In conclusion, we recommend that a portion of capacity prices may be indexed to general inflation or indices of labor costs. In addition, we will consider comments by other parties regarding any additional indexation on capacity prices before we make a final recommendation on this issue. We acknowledge that indexed pricing will require some additional work in the bid evaluation (where time is already extremely tight) and bidders who elect to use indexed bidding will not be as favorably evaluated in terms of price stability.

In its comments, Delmarva indicated that it would agree that bidders may change their price for capacity between the time the bids are submitted and the time they execute a contract with Delmarva. However, such indexing must use widely recognized indices, and must be tied to a provision of the contract that the bidder signs with the equipment suppliers (i.e. there will not be increases in payments under the PPA unless the bidders costs actually increase). Delmarva solicited feedback from the Independent Consultant regarding the proposed indices that could be used.

The Independent Consultant proposed a methodology in its mark up to the RFP to address this issue. Specifically, we recommended that a portion of the capacity price (no more than 15%) could be indexed to a steel price index from the time of bid submission until the bidder executes its EPC contract but no later than two years after contract signing (after that, the capacity price would be fixed), subject to a cap, and another portion could be indexed to general inflation or for labor costs to recover fixed operations and maintenance costs (RFP Section 2.3.1). Delmarva and the Independent Consultant would have the opportunity to approve any proposed indices.

We find Delmarva's proposal to be too limiting and recommend adoption of our proposal on indexing of capacity prices, with the modification that the fixed O&M component to the capacity charge may be adjusted only to an inflation index.[97]

iv. PPA Energy Price

Delmarva's RFP proposes a pricing mechanism for the energy price component. According to the RFP, bidders shall be paid for energy based on the price offered in cents per kWh. This may consist of a starting price plus an escalator or other means of demonstrating the energy price that Delmarva will pay for energy. Bidders may index their price to a publicly available index and must specify the index.

While none of the commenters addressed the PPA Energy Price component, the Independent Consultant suggests that Delmarva should be more explicit with regard to allowable indices. It is assumed that Delmarva would accept known and measurable indices to include in an energy price formula and may want to state in more detail in the RFP the type of indices that are acceptable. Bidders should be able to bid an energy price component that reflects variable O&M costs. Bidders should be allowed to propose such a charge with its applicable index (usually inflation) as a dispatch price component. In addition, Bidders should be allowed to include fuel indices in their price bid, with the energy charge related to a specified heat rate at specified load levels (based on a heat rate curve). This will allow bid prices to relate more closely to costs, which should allow for more aggressive bidding.

v. Residual SOS Cost Impact

The residual SOS cost impact addresses the impact that each proposal is projected to have on Delmarva's total system SOS costs. The impact could be positive or negative depending on the cost structure and operating characteristics of the proposal as well as the impact of the proposal on PJM market prices. As we understand, this cost component captures two impacts: The first is the displacement impact associated with the output from the new generation unit on existing SOS. Since Delmarva is assuming that standard offer service could be acquired at market prices, any residual power could be sold (or acquired) at projected market prices. Second, the market price will potentially be influenced by the presence of the generation unit(s) proposed through this RFP. The impacts on market prices will also be captured in the evaluation. Delmarva states

[97] Based on a discussion with Delmarva's consultant, an index based on labor costs may create difficulties in the evaluation.

in the RFP that the Residual SOS Cost impact will be estimated using computer models to simulate Delmarva's system with both existing and new generating units.[98] The Residual SOS Cost impact will be determined by combining a project's impact under a base scenario with high and low price scenarios to determine the effect of prices that are higher and lower than those anticipated.[99] Also, Delmarva will take price variability into account in the detailed evaluation.[100]

NRG identifies several questions and issues associated with the models and approaches for evaluating bids. These issues will be addressed in the discussion of the models and methodologies used in the evaluation in a subsequent portion of this section.

While Delmarva's focus is on the impact of each proposal on the cost of standard offer service for SOS customers, other utilities have used a similar approach for assessing the system production cost impacts associated with new generation options. In essence, utilities will evaluate the variable cost of the proposal relative to either the market price or marginal system cost in each hour to determine if and when the proposal would be dispatched and displace existing generation. The impact on system-wide production costs is then determined and included in the overall assessment of each bid.

While conceptually Delmarva's proposed methodology does not appear to be problematic, we recommend that Delmarva finalize and identify its proposed methodology for assessing price stability associated with the Residual SOS Cost impact.. We believe it is important for Delmarva to articulate clearly for prospective bidders the methodology that will be used before they need to prepare their bids, especially given the importance of price stability as an evaluation component.

vi. T&D Project Impact

Another cost component included in the analysis is the Transmission and Distribution (T&D) cost impact. According to the RFP, the T&D project impact represents the savings or expense a project causes Delmarva to incur by allowing Delmarva to defer or by causing Delmarva to advance planned capital improvement expenditures to its transmission and distribution system. The cost of any incremental network transmission cost or savings will be added to the cost of the proposal for purposes of the Price Evaluation. This analysis will also assess the benefit or cost of other transmission projects that would be deferred or accelerated as a result of the proposed project. Bidders will be required to provide information on project location, interconnection point and voltage level with their Notices of Intent to Bid on November 22, 2006. Delmarva indicates that the evaluation of transmission impacts will be preliminary and will be used for evaluation only. Bidders will be required to also submit an application for a PJM feasibility and impact study.

[98] The computer model used to undertake the assessment of the Residual SOS Cost impact will be discussed in a subsequent section of this report.
[99] Delmarva has not indicated how the results of these scenarios will be combined in deriving the residual SOS cost impact.
[100] Delmarva has not determined how price variability or the price stability factor will be determined at this point. The Company and ICF are apparently considering a standard deviation analysis on the pricing streams of the proposals as the basis for assessing the level of price stability.

According to Delmarva and ICF, the objective of the transmission modeling analysis is to establish a basis to evaluate the impact of generation proposed under the RFP on the Delmarva transmission system. The analysis will assess the impact on transmission facility loading and possible violations of thermal limits. It is proposed that the analysis will be performed using a four-step process:

- Establish baseline transmission system conditions;
- Determine appropriate transmission projects to mitigate identified overloads;
- Assess impact of proposed generation on Delmarva's transmission system; and
- Assess the financial impact of each proposed generation option on the transmission system.

Delmarva and ICF propose to use several models to conduct the analysis.

NRG is recommending that Delmarva's quantitative estimation of "T&D Project Impact" be limited to five-year duration and that the models used to estimate such impacts must be consistent with PJM's models and assumptions. Also, for any project that will sell part of its energy and capacity into the wholesale market, NRG argues that only that portion of the T&D impact associated with the RFP portion should be considered in the evaluation of its bid.[101]

It is typical in most competitive bidding processes that utilities undertake an assessment of the impacts of proposals on system transmission costs as a major cost component. While the approach for assessing transmission cost impacts may differ depending on the market structure in different regions of the country, most utilities include such a cost category in their evaluation. Delmarva and ICF appear to have developed a detailed process and methodology for assessing transmission and distribution system impacts integrated within the PJM market. In our initial report, we, encouraged Delmarva to address the above questions of NRG in its reply comments.

Delmarva replied that it did not see the basis for limiting the analysis of transmission impacts to five years. We are aware of other RFP processes where the utility has developed a five-year transmission plan and evaluated proposals relative to the impact on the plan. However, if a utility possesses the ability to evaluate transmission impacts over a longer term such an approach would be preferable and we support Delmarva's proposed plan of analysis.

vii. Transmission Savings or Losses

In addition to the transmission and distribution project impacts, Delmarva will also measure the value of energy saved or lost as a result of project operations as a price factor. Delmarva proposes to calculate the saving and losses for every project relative to a reference case utilizing computer models.

As with the transmission system impacts noted above, it is common for utilities to estimate system transmission losses in the bid evaluation process.

[101] NRG comments at 33-34.

viii. Imputed Debt Offset

Delmarva proposes to include an Imputed Debt Offset as one of the price factor components included in the price evaluation. Delmarva proposes to assess the incremental equity amount to be equal to, at a minimum, 50% of the Net Present Value (NPV) of the bid's capacity payment (a percentage of the energy price may be included if Delmarva concludes that a portion of the bid's energy component would be imputed as debt by rating agencies in their assessment of Delmarva's credit worthiness).

The methodology applied by Standard & Poors for calculating the amount of imputed debt to include on the utility's balance sheet is generally based on a risk factor that can range from 30% to 50% based on the perception of the risk to the utility for recovering the costs associated with the PPA.[102] According to S&P, a 50% risk factor is appropriate for long-term commitments. This risk factor assumes adequate regulatory treatment including recognition of the PPA in tariffs. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of purchase-power costs, a risk factor of 30% could be used. S&P considers lower risk factors of 10% to 20% for distribution utilities where recovery of certain costs, included stranded assets has been legislated.

The imputed debt offset[103] is one of the most controversial factors in the competitive bidding environment at this time. In essence, credit rating agencies treat the fixed costs associated with power purchase agreements as debt on the utility's balance sheet. This requires the utility to offset the higher financial leverage associated with the imputed debt by raising equity to rebalance its capital structure. Since equity is more costly than debt, such incremental costs should be assessed. As a result, utilities contend that the debt-like characteristics of purchased power agreements impose a real cost on the utility that should be accounted for in the bid evaluation. Independent generators, on the other hand, argue that no empirical evidence exists to support the claim of the utility that power purchase agreements cause utilities to experience greater financial costs and risk than those that would be experienced if the utility build the equivalent amount of capacity. The concern of the generators is that the application of imputed debt skews the bid evaluation in favor of the utility self-build at the expense of the generator. The same concern may apply where the alternative to a long-term unit contract is a one- to three-year power purchase agreement, which generally would raise fewer concerns on the part of the rating agencies.

Adding to the problem is the fact that there is no consistent agreement among state Commissions regarding the proper treatment of the imputed debt adjustment. As Appendix F demonstrates, nine states have addressed this issue to our knowledge. Of these states, only a few explicitly allow an imputed debt adjustment. States vary with regard to the level of the risk factor, the appropriate timing within the evaluation process to address the imputed debt adjustment, and whether the impact should be accounted for in an RFP process or in a cost of capital proceeding. In a recent decision on its competitive bidding rules, the Oregon Public Utilities Commission stated that debt imputation should not be used as a mechanism to determine an initial short list

[102] A Standard &Poor's publication on the subject—"Buy Versus Build": Debt Aspects of Purchased-Power Agreements" (May 8, 2003)—is attached as Appendix E.

[103] The imputed debt offset is also referred to as imputed debt, debt equivalence adjustment, or equity adjustment.

but ordered that a utility would need to obtain an opinion from a ratings agency to substantiate its claims of the necessity for applying a debt equivalence adjustment.

Three parties submitted comments on this issue. NRG Energy and SCS Energy recommend that the Commission require Delmarva to eliminate this adjustment. Bluewater Wind indicates it understands the utility's concerns but requests clarification regarding the application of the imputed debt offset to a wind project.[104] NRG, for example, raises four points to support its contention that the imputed debt offset is inappropriate and should be eliminated from the RFP process.

- Delmarva is incorrect in its premise that its debt rating will necessarily suffer from entering into a PPA. In assigning debt ratings, the rating agencies consider the totality of a utility's financial position. PPAs and other long-term contracts are but one of many factors that are evaluated in assigning ratings. Delmarva has not demonstrated that entering into a PPA will impose an actual cost upon the Company, and has certainly not proven that this cost can be represented as an incremental amount of equity required to return its balance sheet to pre-existing levels.
- In assigning credit ratings, the agencies are primarily concerned with the ability of the subject company to service its debts. If costs under a PPA are reasonably assured of pass-through in retail rates, the agencies would likely be relatively unconcerned with the PPA.
- Other states regulatory authorities have responded that a utility company may file a rate case in the event of a downgrade by the rating agencies, and may request remedies (such as an increase in allowed return on equity), but that automatic and formulaic adjustments in evaluating proposals for PPAs will not be adopted.
- Inclusion of the imputed debt offset factor in Delmarva's RFP appears to be a thinly-veiled attempt to establish Delmarva-supplied generation as the preferred choice since the imputed debt offset would otherwise hamper all other bidders.

As noted, there are a number of alternative approaches for addressing this issue in a competitive bidding process. The alternatives considered herein include the following:

- Alternative 1: Do not consider an imputed debt offset in the RFP process (given that the impacts may not be certain and the quantitative methodology would need to be refined).
- Alternative 2: Calculate the imputed debt offset aside from the normal bid evaluation process under a lower risk factor (i.e. 30%) to reflect the cost recovery mechanisms for Delmarva in Delaware and determine whether the imputed debt offset has an impact on the results of the evaluation. The imputed debt offset would be used to determine the impacts on the ranking of bids based on the magnitude of this adjustment.

[104] The rating agencies may treat a portion of energy charges under a PPA as being debt equivalent where under the PPA payments are made only for energy or where the capacity payments are very small.

- Alternative 3: Alternative 3 is similar to 2 above but the imputed debt adjustment under the lower risk factor would be utilized consistent with the methodology proposed by Delmarva as a component of the bid evaluation.
- Alternative 4: Only apply the imputed debt offset if comparing the bids to shorter term purchases but not to self-build options. According to the rating agencies, self-build options also contain risk; calculating different adjustment factors for each type of resource is very subjective.
- Alternative 5: Approve of the imputed debt offset as proposed by Delmarva.

The Independent Consultant supports alternative 2 above whereby an imputed debt offset is calculated but is used for "sensitivity" purposes as opposed to an explicit direct impact on the bid evaluation process. Given the structure of the Act and an order likely to be issued by the Commission approving entry by Delmarva into a PPA and a rate recovery mechanism, we believe that the risk factor would likely be lower than the 50% proposed by Delmarva to reflect the high likelihood of cost recovery for a contract entered into as a result of this process. We also recommend that Delmarva include a spreadsheet in the RFP (as an Appendix) that describes the imputed debt offset methodology proposed by Delmarva and a means to calculate the impact of a particular proposal.[105]

Several questions have been raised about the imputed debt offset. SCS Energy urges that the Commission adopt Alternative 1 (imputed debt offset would not be considered in the RFP process). NRG suggests that the Independent Consultant's recommendation to apply Alternative 2 appears to be an attempt to reach a compromise that is not justified. NRG requests that the Commission direct Delmarva to remove the Imputed Debt Offset as any type of factor in this RFP process. NRG states that there may be some merit in a proposal (similar to that of the Oregon Public Utilities Commission and cited in the Report) that would require Delmarva to go back to the rating agencies to determine the impact of a proposed PPA on its credit rating. Delmarva questions the use of a 30% risk factor in the evaluation instead of the proposed 50%. Delmarva states that the 50% risk factor is consistent with the S&P methodology and should be used as the base case.

The comments of the parties mirror the variation of approaches for assessing imputed debt as identified in Appendix F to our report. Furthermore, there is still a significant degree of uncertainty regarding many factors associated with imputed debt including the impacts of PPAs, the appropriate risk factor, and whether this issue should be included in the evaluation of bids or be addressed in cost of capital proceedings later. Since the State Agencies will ultimately be making the decision regarding the appropriate resource to select, if any, it is appropriate to use in a sensitivity analysis a risk factor that pertains to the situation presented here—a distribution utility that would enter into a contract directed by regulatory agencies pursuant to legislation that provides for recovery of the costs of approved contracts in rates. Standard & Poor's guidance states:

[105] This is consistent with other RFP processes where the utility has either described the evaluation methodology in the RFP (e.g. Progress Energy) or attached a spreadsheet of the methodology in the RFP (e.g. Cleco Power and Public Service Company of Oklahoma).

> For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, included stranded assets, has been legislated.[106]

NRG has pointed to language from Moody's that states that where there is a clear ability to pass through purchased power costs to customers, Moody's would not regard the PPA has having long-term debt-like attributes.[107] This supports our recommended approach where the base case would have no imputed debt offset and where the sensitivity case would have a 30% risk factor. This is also consistent with treatment by other regulatory commissions, where the pertinent range for considering imputed debt offset has been 0-30%. It would be reasonable for the State Agencies to request Delmarva to provide a report from Standard & Poors (such as suggested by the Oregon Commission) should imputed debt significantly influence bid ranking and selection.

ix. Loss Under Probability of Default; Exposure

As part of the price stability evaluation, this price factor is intended to address the potential economic cost impact to Delmarva's end-use customers in the event of a default by the Seller. The analysis assesses the credit risk of the bidder's proposal using measurements of the default probability (based on credit quality and the likelihood of default based on a bidder's credit rating), credit exposure (based on contract size and pricing relative to forward market prices), and recovery rate. The overall exposure will be assessed as the net present value of the exposure to Delmarva's SOS customers. This is a form of credit value at risk analysis.

NRG has raised serious concerns over the application of the Loss Under Probability of Default component:

> NRG urges the PSC to apply a healthy measure of skepticism to Delmarva's proposed evaluation methodologies. Although it is appropriate to evaluate offered capacity and energy prices together on a common basis, NRG submits that such possible contingent costs as "Loss Under Probability of Default" cannot be reliably measured over the lengths of time that Delmarva is proposing. For each bidder, Delmarva is proposing to: (1) estimate the likelihood of default and the timing of such default over the life of the PPA, (2) estimate the cost of replacement power (energy, capacity, ancillary services and other attributes) beginning at the time of default and running through the end of the proposed PPA, (3) estimate the offsetting economic value of its security and any claims that may be realized through legal processes, (4) combine all the probabilities and loss or gain values mathematically (i.e. by means of a convolution approach), and (5) discount everything back to a present value figure that can be compared among all bidders. In other words, Delmarva is proposing to perform a quantitative "Expected Loss and

[106] See Appendix E at 2.
[107] Comments of NRG Energy, Inc. on Independent Consultant's Report at 8.

> Recovery” analysis over time periods that may range up to 30 years into the future and may involve a number of disparate generating technologies. (p. 13).

As NRG notes, the calculation of the loss under probability of default involves a number of factors that will influence the final results including the default rates by credit rating, time at which the bidder defaults, the timing of and level of recovery, etc. This is a very complex analysis.

The Independent Consultant has major concerns regarding the usefulness and appropriateness of this analysis. The methodology purports to assess the exposure of Delmarva’s SOS customers due to a PPA that would be entered into by a bidder. A lower exposure would mean a higher score. A higher exposure would provide a lower score. Yet, two of the key components in the analysis do not work well in this context. First, the amount of credit exposure is based on the mark-to-market exposure, which is a function of the market price minus the PPA price. If the PPA price is high relative to the market price, there is relatively little or lower credit exposure. This analysis tool would appear to favor projects with high pricing. Second, the default rate is not based on the probability that a seller will default under its obligations pursuant to the PPA (especially during the pre-operational period when the risk of default is highest), but is based solely on the seller’s credit rating (or its guarantor’s credit rating) and the probability that companies of that credit rating default on their debt obligations, as determined by the rating agencies. We are not aware of any other competitive bidding processes where such a price factor has been employed. While some utilities have used a similar methodology as part of their credit assurance assessments, we are not aware of such a methodology being applied for price evaluation.

For the foregoing reasons, we recommend that this price factor be eliminated. However, we are sympathetic to the underlying reason for inclusion of this price factor in the analysis—that there should be some measure of SOS customer exposure based on bidder creditworthiness and other factors. We recommend that 6 points should be allocated to a category, which we will call “Exposure.” The key factors in this category would be contract size (greater contract sizes create greater exposure to SOS customers, capacity factor and dispatchability, bidder creditworthiness, and contract duration. Any contract size of 200 MW or less with an investment grade seller for 10 years would receive all six points. A baseload project of 400 MW that is non-dispatchable (i.e., has no ability to ramp down to less than full load once it is on line) for 25 years with a non-investment grade seller would receive zero points. Points would be allotted in between based on project size, capacity factor relative to a baseload project, contract term (a 10-year term would impose less exposure than a 25-year term), seller credit rating and dispatchability of the project. This analysis would be straightforward. Bidders of large projects would be allowed to bid up to 400 MW, but the added exposure above that associated with a 200 MW baseload project would be considered as creating additional exposure to ratepayers in the bid evaluation analysis.

Delmarva Power strongly opposes eliminating the Loss Under Probability of Default price factor as we have proposed. However, as we have stated, we are unaware of any such factor being included in other competitive bidding processes for power supplies as a price factor and we do not believe it is appropriate in this context (regardless of its potential use in establishing credit requirements, which could be questioned). Moreover, it appears very complicated to implement and given the limited time available to perform the evaluation, we believe that such an untested tool in performing bid evaluation would detract from the credibility of the bid evaluation and the necessity of an expedited evaluation. Our proposal to reflect exposure is more straightforward and verifiable, is easier to implement and takes into account risk factors due to seller creditworthiness.

x. Price Stability Evaluation

As noted above, Delmarva proposes that 20% of the weighting be based on Price Stability. Delmarva proposes to assess both the stability of the price stream for the project (energy costs) and price variability associated with Residual SOS Cost Impacts. Delmarva also proposed assessing the variability of the Loss under Probability of Default component in its evaluation of price stability (an evaluation methodology that we have proposed to be replaced, as set forth above). While the RFP discusses the issue of price stability and provides some discussion of the components it will consider in assessing price stability, there is no discussion of the quantitative metric Delmarva will calculate as the basis for calculating the price stability associated with each bid (i.e. standard deviation of the price stream) or the use of that metric for calculating the points associated with each bid. In our initial report, we requested that Delmarva provide a clearly stated explanation of its proposed methodology on this important evaluation factor. In its reply comments, Delmarva identified a four-step process it will use to analyze the price stability attributes of bids. We recommend that this description be included in the RFP.

xi. Economic Evaluation Methodologies and Modeling Issues

The economic evaluation methodology is an important aspect of the RFP process and one which garners significant attention from bidders and other interested parties. There are a number of issues associated with the economic evaluation and modeling of bids common to most competitive bidding processes. These include:

- The appropriate models and methodologies for evaluating the proposals requested given the types of products and resources solicited.
- The integration of the RFP with the IRP process.
- The appropriate methodology or metric (i.e. total system PVRR, $/kW, $/MWh) for converting the economic analysis results into a price score or points for comparison with non-price factors.
- The evaluation of bids with different terms.
- The evaluation of bids with different capacity and energy amounts relative to the amount of capacity and energy required.
- The basis for evaluation and selection.
- Consistency of the input assumptions between the IRP and RFP.

Utilities have used a wide range of models and methodologies to undertake the assessment of bids, including simplified price screening methodologies and more sophisticated production costing and generation expansion models. Some utilities have used detailed spreadsheet models that have some dispatch resolution.

This section of the report will address the economic evaluation methodologies and models proposed by Delmarva for the bid evaluation process, including the cost analysis and price stability assessment.

One of the most common approaches taken in the industry is for the utility to use the same models for developing the IRP as for undertaking the evaluation of bids received. This approach generally involves sophisticated production cost or generation expansion models that allow the utility to undertake a system-wide assessment including direct and indirect costs (i.e. costs or benefits associated with the displacement of other resources based on system dispatch) for the bids received.

ICF International has been retained by Delmarva to assist in the preparation of the Integrated Resource Plan as well as the RFP. ICF will use its Integrated Planning Model (IPM) and integrated data system as the main analytical tool for this analysis. The IPM model evaluates potential expansion options, including new capacity options, transmission builds, demand side management and other options. The model minimizes system cost over the time horizon by assessing power plant dispatch for existing units, new entry options, grid operations and transmission considerations, environmental specifications, electricity demand and fuel input prices. In addition, the model estimates forward zonal power prices in PJM and captures transmission, environmental and fuel constraints. The output projections from the model include:

- Power Prices
- Fuel Prices
- Allowance Prices
- Asset Values
- Dispatch Decisions
- Capacity Build Decisions
- Emissions
- Compliance Costs
- Compliance Decisions
- Plant Retirement Decisions

While the IPM model serves as the key tool in the evaluation, ICF integrated analytical framework also includes the following models: (1) GE-Maps for the analysis of location-based marginal prices (LMP), congestion and losses; (2) PowerWorld for evaluation of the transmission grid, interface capabilities, and critical contingencies; (3) MANGAS for gas supply evaluation and (4) CoalDom for evaluation of coal supply.

NRG has raised several issues with regard to the modeling methodology. First, transparency of the process is not encouraged since Delmarva has not identified the computer models to be used in the analysis. Second, all models and input assumptions used by Delmarva to quantify these costs must be fully disclosed, transparent, verifiable and available to all RFP participants on a non-discriminatory basis. Third, the use of mathematical models beyond their range of reliable prediction may serve to bias the selection against long-term PPAs, and the capital-intensive solid fuel, base load projects that require long-term PPAs.

Based on the Independent Consultant's meeting with Delmarva and ICF and review of the information about the modeling methodology, it appears that the modeling methodologies are consistent with industry applications for both the Integrated Resource Planning process and for the RFP. Of importance is the fact that the analytical tools and framework will be consistently applied to both the IRP and RFP, which should ensure consistent evaluation results.

It is our understanding that the model will address the term and size issue for different bids by assuming that SOS, contracted from the market, will be used as the marginal resource. In cases where bids have a lower capacity level than is required or a shorter term, the forecast of the market prices based on the forward curve produced from the model will be used to meet the marginal requirements. Likewise, if some existing SOS contracts are displaced as a result of a contract, the power will be sold into the market at the market price. This process is consistent with approaches used in the industry and should provide consistent and reasonable results.

With regard to the comparison metric, it appears from the Proposed RFP that Delmarva intends to use levelized cost per kWh (page 9). However, it is not clear if Delmarva has decided on that specific metric or is still in the process of trying to determine the appropriate metric. In light of the current uncertainty concerning the metrics to be used in the bid evaluation, it is premature to determine a scaling system to convert economic price scores to points.[108] Usually, a scaling system is determined after the detailed economic evaluation methodology. We recommend that this be effectuated by the Independent Consultant in cooperation with Delmarva at an early date, but no later than the due date for submission of bids.

In any case, the Independent Consultant has recommended that "test bids" be established and run through Delmarva's evaluation process (including price and non-price evaluation) to ensure the process is consistent and effective and produces unbiased and consistent results. The test bid process will include the Independent Consultant actually completing all the bidding information requirements as any other bidder would and working with Delmarva through the evaluation of the bids, including reviewing model operations and results from the assessment. If any issues emerge with regard to the operations and results from the models that could create biased or nonsensical results it is important to address these issues before bids are received and evaluated. In this regard, the Independent Consultant will develop bids for several different technologies,

[108] Delmarva has proposed a system that allocates points between scores based on their "expected cost," with the lowest cost receiving 40 points and other bidders receiving a percentage reduction from 40% based on the percentage by which their cost is determined to be higher than the lowest cost bidder. See RFP Section 2.5 at 18.

including an IGCC project, a wind project, and a gas-fired combined cycle plant to check that there are no inherent biases favoring one particular option.

The Independent Consultant has reviewed the information included in the Bid Forms with regard to proposal pricing and operational information requirements and initially finds the information to be consistent with the requirements of the modeling evaluation. One exception appears to be that the RFP does not request information on the targeted equivalent availability for the proposed unit even though this is an important component of capacity payment requirements (see page 9). It is typical in other RFPs that the information required for the models to be used by the utility be consistent with the information requested in the bid forms. We have modified the forms to address this concern.

It is the experience of the Independent Consultant that bidders may not accurately provide their pricing formulae thereby requiring the utility to seek clarification of the formulae proposed. If the utility has to go back to the bidders to seek clarification of the pricing proposals, this can delay the evaluation process. Delmarva's request for pricing information and formulas is fairly general with no specific pricing schedules or formulas that the bidder has to complete. We have provided more specific information requests in proposed changes to the bid forms and will work with Delmarva regarding any changes that may provide further clarification and ease of use for bidders.

Finally, NRG has requested that the models and input assumptions used by Delmarva to quantify the costs must be fully disclosed and available to all RFP participants on a non-discriminatory basis. This suggestion is contrary to general standards in the industry. Only on rare occasions do the utilities provide models to prospective bidders, and when the utility has provided the models it is generally a spreadsheet-based model, not a proprietary third-party model. Furthermore, the role of the Independent Consultant in this process is to review the results derived by Delmarva and/or undertake an evaluation of the bids to determine if Delmarva's results are accurate and reasonable. Requiring Delmarva to provide the models will likely result in delay in the process that is not needed in light of the involvement of the Independent Consultant. Accordingly, we recommend that Delmarva should not be required to provide its models to all RFP participants.

In its comments on the Independent Consultant's report, NRG reiterates its position that full transparency with respect to the modeling inputs and methodologies is essential to provide bidders with assurances that the economic analysis of their bids is being appropriately conducted.

Delmarva opposes review of its economic evaluation methodology by the Independent Consultant until after the economic analysis is complete, opposes test bids, and states that it is not premature to scale the pricing analysis based on use of levelized prices.[109]

NRG and Delmarva have taken extreme positions, with NRG advocating total transparency with all bidders and Delmarva advocating no transparency, even to the State Agencies and their consultant, until after the analysis is complete with little or no time to rectify any problems. Both approaches are highly problematic. As noted, it is contrary to industry practice for the utility to

[109] Comments on the Independent Consultant's Report at 29.

provide its models and detailed methodologies to the bidders. This would likely create substantial delays in the process for which there is no time, the models are proprietary and could not easily be released, and the process could be inequitable to smaller bidders who do not possess the resources to operate the models.

Delmarva's approach is even more problematic. The State Agencies are ultimately responsible for making determinations with respect to the bid evaluation under a legislatively mandated process and timeframe. A flawed evaluation methodology cannot be fixed, or at least easily fixed, on an after-the-fact basis within the constraints of the process. Hence, it is critical that the State Agencies through their consultant fully understand the methodologies and assumptions used and have the ability to raise any questions and seek modifications prior to receipt of the bids not after the bids have been reviewed and evaluated.

The objective of the test bid process is to assess the bid evaluation methodology in advance of bid receipt to gain a perspective on the process and to verify the consistency, efficiency and reasonableness of the modeling methodologies and input assumptions. It is important for the integrity of the process that the input assumptions and methodologies be locked down prior to receipt of bids and that the assumptions and methodologies do not contain undue bias toward any resource. We recommend that test bidding be conducted unless we agree that it is infeasible to do so within the timeframe and we are otherwise provided with sufficient information and input that we become comfortable with the bid evaluation process, methodologies and assumptions. With regard to the price evaluation, we reiterate the need for an agreement on the price evaluation metric (which still appears uncertain) before a scaling approach is determined. We are in discussions with Delmarva and ICF to commence this process. To address NRG's concerns, we recommend that Delmarva either spend a significant portion of the bidders conference describing and explaining its bid evaluation methodology and process or provide more detailed information later after there is further refinement in the methodology and process. It is important for bidders and other interested parties to have a reasonable amount of information as to how the bids will be evaluated and what information they need to provide with their proposals.

xii. Input Assumptions

Development of the modeling input assumptions is an important task in the bid evaluation process. Input assumptions include, among other factors, fuel forecasts, discount rate, market price forecast, inflation forecast, emission cost, cost of new entrants, etc. It is our understanding that the market price forecast will be projected internally within the modeling analytics proposed by Delmarva. However, the Delmarva RFP does not provide information about the forecast for input assumptions.

NRG comments that any mathematical model is only as good as its underlying assumptions and data inputs. The forecast of input assumptions can serve to bias the results of the analysis if not consistently developed.

Usually, the input assumptions are developed and "locked down" prior to receipt of the proposals. In addition, it is typical that the input assumptions are developed within a consistent framework of forecasting fuel and inflation rates, which are generally linked.

The Independent Consultant intends to closely scrutinize the input assumptions to ensure there are no inherent biases in the forecasts of these variables and that the forecasts are reasonable. Again, the test bid process will be a valuable exercise in assessing the reasonableness of the input assumptions and in ensuring there is no inherent bias.

D Non-Price Factor Evaluation

The Act states that the Proposed RFP shall "set forth proposed selection criteria based on the cost-effectiveness of the project in producing energy price stability, reductions in environmental impact, benefits of adopting new and emerging technology, siting feasibility and terms and conditions concerning the sale of energy output from such facilities."[110] In approving or modifying the RFP before it is issued, the Commission and Energy Office are directed to "ensure that each RFP elicits and recognizes the value of:

a. Proposals that utilize new or innovative baseload technologies;
b. Proposals that provide long-term environmental benefits to the state;
c. Proposals that have existing fuel and transmission infrastructure;
d. Proposals that promote fuel diversity;
e. Proposals that support or improve reliability; and
f. Proposals that utilize existing brownfield or industrial sites."[111]

Thus, it is clear that non-price considerations are an important aspect of the project recruitment and selection process.

Delmarva's Proposed RFP assigns 40 points out of a total of 100 to non-price factors. The total allocation of points to price and non-price categories is discussed above in Section VI.C.i of this Report. This Section addresses the allocation of points within the non-price categories, as well as the criteria within the various categories, and the use of the non-price category scores in computing the Favorable Characteristics and Viability "super categories" described in Section VI A above. Should the Commission and Energy Office determine that a change in the allocation of points between the price and non-price components is warranted, the discussion below will be able to be applied to the points allocated to non-price factors.

As noted above, the Independent Consultant recommends that, in addition to computing the total points scored by each project, the score in each of three "super categories"--Economics, Favorable Characteristics, and Viability—should be assessed separately for acceptability. The Non-Price Factors can be divided into the latter two super categories (with the exception of contract terms). Favorable Characteristics, consistent with the non-exclusive selection criteria outlined in the Act, include Environmental Impact, Innovative Technology, and Fuel Diversity

[110] 26 Del C. § 1007(d).
[111] 26 Del C. § 1007(d)(1).

using the factors discussed in this Section below. Viability includes Operation Date and Certainty, Reliability of Technology, Site Development, Bidder Experience, Safety and Staffing, and Project Financeability.[112] The Independent Consultant recommends that the points awarded for each of these factors be grouped in the manner described in this paragraph as an aid in guiding the State Agencies' exercise of discretion regarding the selection of proposed projects for an award of a PPA.

Recommendations regarding the determination of points for each factor and the criteria to be used for selection within categories are provided in the balance of this section.

i. Appropriateness of Factors/Criteria and Weighting

Section 2.4.1 of the Proposed RFP lists the "Non-Price Factor Evaluation Criteria and Weightings" as follows:

A.	Environmental Compatibility	7
B.	Operation Date and Certainty	4
C.	Reliability of Technology	5
D.	Fuel Diversity	7
E.	Site Development	5
F.	Bidder Experience, Safety and Staffing	5
G.	Financial Plan	5
H.	Contract Terms	2
	Total Non-Price Points	**40**

As a number of commenters have noted, this list is not exactly as specified in the Act. Further, some of the non-price factor descriptions in the Proposed RFP are too imprecise to adequately inform potential bidders how their proposals will be scored. In addition, many commenters also are concerned that the allocation within the non-price factors is inconsistent with the Act. The individual factors in relation to the Act are discussed below.

ii. Factors

a. Environmental

The Act states that the selection criteria are to include "reductions in environmental impact" and recognize "[p]roposals that provide long-term environmental benefits to the state." Delmarva has attempted to address this by allocating seven of the forty non-price points to "Environmental Compatibility." The Proposed RFP provides more specificity by citing "[r]eductions in environmental impact," including "[r]eductions in the level of air emissions," "[i]mpacts on

[112] The Viability super category also takes cognizance of a variety of selection criteria outlined in the Act—projects that contribute to reliability, projects that use existing infrastructure, and projects that use existing brownfield or industrial sites.

water emissions and quality," and "[l]and impacts." Delmarva also states that, "In general, proposals will receive favorable scoring only to the extent that they demonstrate that their project(s) exceed regulatory requirements."

A number of commenters have expressed concerns about Delmarva's proposals in this category. The Delaware Nature Society stated that the Act gives the second highest priority to environmental impacts and that the category, therefore, merits more than seven points out of the total of 100 available. The Delaware Public Advocate supported weighting environmental criteria at 30% of the total score, citing the comments of Professors Firestone and Kempton. The Delaware Energy Office expressed concern regarding the proposed weighting of the environmental category. The potential bidders also suggested that environmental factors should be more highly valued in the project evaluation process, with NRG recommending 10 points, and Bluewater Wind stating that the category should be accorded the greatest number of points after price/price stability. Bluewater questioned how scoring would work if points were only to be awarded for projects exceeding regulatory requirements. Bluewater further noted that with Delaware's participation in the Regional Greenhouse Gas Initiative, reduction in CO2 should be an important scoring consideration. SCS Energy concurred, requesting greater emphasis on "the full range of potential benefits to Delaware's environment from each bidder's project." SCS observed that the proper metric is to compare the environmental impact of projects responding to the RFP with the "emissions and other impacts that would result from the business-as-usual patterns of electricity consumption projected for the state." Professors Firestone and Kempton assert that environmental impacts, including health impacts, should be systematically quantified and such quantification incorporated into the bid evaluation scoring system.

Based on our review of the Act and the comments, the Independent Consultant recommends the following changes to the Proposed RFP:

1. The category should be renamed "Environmental Impact" to reflect the Act more accurately, which refers to "reductions in environmental impact."

2. We recommend that the weight attached to this factor should be increased to 14 points out of the 40 assigned to non-price factors. While a higher weighting (or even a lower weighting) could be argued from the statutory language, we think that assigning 14% of the total score and 35% of the non-price category to environmental impact strikes a reasonable balance with other weighting considerations (particularly in light of our recommended use of super categories by which environmental impact will be a major part of the Favorable Characteristics category). For example, assigning a higher value would require a lower weighting to factors that assess the viability of a proposed project. Factors such as financeability, site control and bidder experience are important in an assessment as to whether the environmental benefits associated with proposed projects will actually be achieved. Accordingly, we encourage the Commission and Energy Office to provide a greater weight to environmental impact but one that allows the other aspects of a successful project to also have importance in the RFP selection process.

3. The description of the category should also be clarified. Bluewater Wind's question on scoring should be answered by awarding points based on the absolute environmental impact of each project, rather than on how emissions compare to regulatory requirements. For example, a coal plant that meets its air emission requirements should be scored lower than a wind or solar project that has no air emissions.

4. In adding specificity, the Independent Consultant suggests that projects be scored based on their: (a) greenhouse gas emissions, (b) mercury and EPA criteria pollutants such as NOx, SO2, particulate matter, and ozone; (c) water impacts including water usage and discharge, (d) land usage, (e) wildlife impacts, and (f) waste disposal. Each of these criteria would be scored on the basis of high, medium, or low/no impact. Delmarva has suggested using specific quantifiable standards (such as emissions per MWh).[113] To the extent that a scalable metric can be readily applied, the Independent Consultant favors the use of more quantifiable point allocations within these items and will work toward that end. As part of the evaluation, direct impacts benefiting Delaware would be considered for each item listed above. For example, if the building of a proposed facility would also lead to a *commitment* to operate another facility with high emissions less often, the resulting committed environmental impacts would be considered in the scoring. We are not suggesting a generalized analysis of the impact on emissions from other generating plants, as Delmarva suggests, but rather a direct tie between emissions from the proposed plant and a commitment to reduce emissions from another unit or units.[114] Weightings would be assigned to the issues of greatest import. In that regard, we recommend that (a) and (b) be given greater weight than the other listed items. The Independent Consultant recommends that scoring within this factor be determined using four points for (a) and (b), and one and a half points each for items (c), (d), (e), and (f). We will work with Delmarva to develop greater detail on these items. These points would be assigned on the impact per MWh expected to be produced. We do not believe that a systematic quantification of all environmental impacts is necessary to provide appropriate weight to the environmental considerations pertinent to the bid evaluation; nor would such a quantification, with the need to resolve or at least address differences in opinion, be practical to incorporate within the context of the expedited time frame and processes required under the Act.

b. Operation Date and its Certainty

The Proposed RFP assigns four of the forty non-price points to this criterion. Delmarva proposes to award more points to projects that will be in-service sooner. In determining this, Delmarva states that "[e]ach proposal will be judged as to the reasonableness of its project plan in terms of meeting its proposed commercial operation date."

[113] Comments on Independent Consultant's Report at 31.

[114] We do not agree with SCS Energy (reply comments at 3-4) that considering a commitment to reduce the emissions of another facility would be against public policy or would be discriminatory. However, the validity of the commitment and the duration and extent of any such voluntary reduction would be evaluated (for example, no credit would be given for a plant that would be required to be shut down and limited credit would be given for a plant with a limited useful life).

The Independent Consultant did not see any comments that expressed concern about this criterion. Indeed, earlier rather than later in-service dates do appear to further the purposes specified in the Act, although this criterion is not specifically mentioned. Assigning four points to this is reasonable, but we recommend that the allocation be reduced to three in order to help allow the Environmental Impact factor to receive greater weight. This small change should not be significant given the other factors that consider the project's overall viability.

The final RFP should specify how these points will be allocated. One reasonable option, which we recommend, would be to award one point for each year before 2013 that the project can reasonably be expected to be in-service (up to a maximum of three).

c. Reliability of Technology and Innovation

The Proposed RFP assigns five points to this factor. It states: "Projects will be judged on the technical maturity of the generating technology proposed. . . . Maximum points will be awarded to those technologies which have achieved the target availability specified by the bidder over at least three consecutive years of commercial operation . . . ." The Proposed RFP then states, "As required under the Act, Delmarva will provide a preference for projects using innovative technology (e.g., coal gasification), based on the performance guarantees offered by the bidder."

The Act clearly specifies a preference for "new or innovative baseload technologies." While not directly addressing the technology reliability, the Act does direct consideration of supporting or improving reliability. Further, to achieve the Act's overall goals, it seems clear to the Independent Consultant that pursuit of innovative technology should not occur to the exclusion of contracting with projects that have a reasonable likelihood of generating electricity as projected by the project developer.

SCS Energy expressed concern that the Proposed RFP gives minimum points to new technology and maximum points to conventional technology. Specifically, SCS notes that an IGCC plant will not meet the three-year standard proposed by Delmarva. NRG and Bluewater Wind offer similar concerns noting the potential conflict between pursuit of innovative technology and Delmarva's concern with project performance and availability. NRG recommends that the RFP specify "a clear and unambiguous point ranking system to encourage innovative technologies as required by [the Act]." To accomplish this, NRG proposes that IGCC and solar photovoltaic projects receive five points in this factor, off-shore wind and biomass using poultry waste receive four, fuel cells, on-shore wind, industrial cogeneration and other forms of biomass receive three points, coal plants using supercritical steam cycles with full post-combustion pollution controls receive two points, and natural gas and sub-critical coal-fired steam units receive one point.

As noted above, the Act states that selection criteria should value innovative technology as well as proposals that support or improve reliability. The Independent Consultant agrees that assigning five of the forty non-price points to this factor is reasonable. Further, we agree, in part, with Delmarva's efforts to balance innovation and reliability, but we recommend that there be a defined allocation between these two criteria. Specifically, we recommend that three points out of the five for this factor be allocated to innovation and two points be allocated for a technology's reliability.. We think, however, that the Proposed RFP too narrowly defines the reliability component. For example, while technology with a strong commercial track record should score better than a technology with no track record, a technology with some track record and strong performance guarantees should be given consideration in the point scoring.

d. Fuel Diversity

The Proposed RFP assigns seven points to fuel diversity. In describing this factor, Delmarva specifies a preference for renewable resources and facilities that use solid fuel. The Proposed RFP also states a preference for projects that use diverse fuel sources and notes that this factor is already incorporated into the price stability evaluation discussed above.

This factor is specifically identified in the Act, which directs the Commission and Energy Office to recognize the value of proposals "that promote fuel diversity."

Bluewater Wind provided brief comment on this topic. Bluewater questioned the basis for preferring solid over liquid fuel and wondered whether a wind project would lose points under the Proposed RFP language. Bluewater suggested that points should be awarded based on increasing the diversity of fuel used in Delmarva's service territory and not be dependent on whether the facility uses multiple types of fuel.

The Independent Consultant agrees with Bluewater to a point. We think that the reference in the Proposed RFP to preferring <u>renewable and solid fuels</u> is reasonable since SOS customers' costs are related to PJM market prices (at least forward market prices) which, in turn, are driven in large part by volatile natural gas prices. As noted in the Proposed RFP, aspects of this factor are captured in the price stability scoring; we, therefore, recommend that the non-price factor weighting be reduced from seven to three points (with the other four points being allocated to Environmental Impact). While we do not disagree with factoring the use of multiple fuels in this category (as, for example, the use of oil as a substitute fuel for natural gas), we recommend that single fuel-source projects such as wind, that add diversity and reduced volatility to the power supply mix, should be given the most weight. We are not suggesting, as Delmarva suggests, that an analysis be conducted of the makeup of the Delmarva SOS power supply, an impossible and non-productive task.

e. Site Development

The Proposed RFP assigns five non-price points to site development. The description in the Proposed RFP focuses on site control and siting feasibility including permitting, the use of brownfield or industrial locations, and certain socioeconomic issues.

The Act identifies both siting feasibility and the use of existing brownfield and industrial locations as important considerations.

NRG observed that the Act specifically favors the use of brownfield or existing plant sites. These items are listed in the Proposed RFP. NRG offered the following detailed criteria for this factor: site control, the ability to satisfy zoning requirements, and siting feasibility for the project, including fuel delivery and transmission infrastructure. NRG also commented that a criterion for permitting should be added.[115]

The Independent Consultant recommends that this factor should receive five points in the evaluation and will propose a minor redrafting of this text so that it is more harmonized with the Act. Specifically, we recommend that permitting be considered as part of the siting factor. In a revised RFP, information should be requested regarding a bidder's permitting plan for the site, which will be reviewed for its level of development and reasonableness.

f. Bidder Experience, Safety, Staffing

Delmarva has proposed assigning five points to bidder experience, safety and staffing. In describing these terms, Delmarva seeks qualifications of key personnel, as well as the overall experience of the bidder on the functions needed to complete and operate a project. Delmarva also requests information about the bidder's track record and plan for safety.

Again, the Act does not explicitly address these items, though bidder experience and safe plant operation are fundamental to achievement of the Act's goals.

Limited comment was provided on this factor. Bluewater Wind briefly concurred that safety is important and encouraged a review of the entire project supply chain "based on OSHA or comparable metrics."

The Independent Consultant agrees that a bidder's experience is highly relevant to the viability of a project proposal. We agree that the credentials of the people specifically assigned to the particular project are a key component of assessing this factor. We also agree that five points is reasonable in combination with the other factors that also address the ability of the bidders to complete their proposals. We do not recommend a requirement that a detailed supply chain safety assessment is needed.

g. Financial Plan

The Proposed RFP assigns five points to an assessment of the ability of the bidders to finance their projects. This assessment would include evidence of commitments from financial institutions and a financial plan for project-financed development. For corporate financing, the bidder would need to demonstrate its financial strength and appropriate financial relationships to obtain the necessary capital.

The Act does not explicitly identify this factor, yet it is fundamental to determining the realistic chances that a project under consideration will actually be completed. Because the Act is designed to produce operating projects that further the stated goals, the Independent Consultant recommends inclusion of this factor which is a standard component of project review.

[115] NRG comments at 21-22.

In this regard, NRG observes that the term "Financial Plan" should emphasize the project's financeability rather than whether a defined plan is already in-place. As NRG notes, financing commitments are not put in-place until a power purchase agreement is signed. NRG proposes that bidders be required to provide letters of intent or support in lieu of definitive commitments.

The Independent Consultant agrees that this factor should receive five points. In assigning points to proposed projects, project financeability should be the focus. Thus, we would rename this factor "Project Financeability" and change the description to reflect the observations of NRG concerning the way in which projects may be financed. While a demonstration that a bidder has a reasonable plan and the ability to finance its proposed project is also a threshold requirement, a major difference with this evaluation factor is that the threshold requirement provides a minimum hurdle for all bidders while at the review stage this criterion evaluates the relative strength of the bidder's financial plan and capabilities.

h. Contract Terms

Delmarva proposes to award two points based on "bids with the fewest and least substantive changes" to the full PPA that is proposed to be provided in November to bidders who file a Notice of Intent. At the same time, Delmarva has listed a number of terms in the Proposed RFP that it states are non-negotiable.

The Independent Consultant did not note any substantive comments on this topic from potential bidders. However, we are not satisfied with the description. If the proposed changes are reasonable, the number of requested changes should not be viewed unfavorably. Alternatively, if the changes requested (even if few in number) are unreasonable, Delmarva is under no obligation to accept them and the contract will be at risk of not being executed if the bidder is unwilling to change its position. As a result, we favor a clear statement that proposals will be judged on the reasonableness of the requested changes, which includes the impact of the proposed changes on the ratepayers' interests and to a lesser degree, the complexity and cost required to resolve the proposed changes. We have recommended that the points for this factor be reduced from two to one to allow greater weight for the Exposure evaluation factor (see Section VI.C.ix of this report).

i. Summary

In view of the discussion above, we recommend that the RFP use the following "Non-Price Factor Evaluation Criteria and Weightings" assuming a 40-point allocation (if a larger number of points is allocated to this area, then the factors should be adjusted proportionately):

A.	Environmental Impact	14
B.	Operation Date and Certainty	3
C.	Innovation of Technology and Reliability	
	1. Innovation	3

	2. Reliability	2
D.	Fuel Diversity	3
E.	Site Development	5
F.	Bidder Experience, Safety and Staffing	5
G.	Project Financeability	5
	Total Non-Price Points	**40**
H.	Contract Terms	1
	To be included in Price Points	**1**

For purposes of the two non-price super categories (Favorable Characteristics and Viability), scores in categories A, C1 and D (20 points total) will be added to provide a score for Favorable Characteristics, while categories B, C2, E, F and G (20 points) will be added to provide a score for Viability. As noted above, the Contract Terms category (H) will be considered as part of the 60 total points available for Economics.

VII Term Sheet Conditions

Our assessment and recommendations as to the major terms and conditions set forth in Delmarva's proposed Term Sheet are addressed below. We plan to provide a mark-up to Delmarva's proposed term sheet by September 26.

A Milestones/Liquidated Damages/Pre-Operational Termination Rights and Consequences

Delmarva has proposed that the permitting milestone be set at 18 months after the Effective Date (the defined "Permitting Completion Deadline"). At this point in time, Delmarva accords any Seller which has made "all commercially reasonable efforts" to obtain the permits, the right to terminate the PPA if it has been unable to obtain all necessary permits. Upon termination by the Seller, Delmarva returns $50/kW from the Development Security and retains $50/kW as Liquidated Damages. However, if the Seller notifies the Buyer that it has not obtained such permits within 18 months of the Effective Date, but that the Seller prefers a six month extension, the Buyer will allow the extension if the Seller agrees to pay the full amount of Development Period Security--$100/kW--if it is unable to get all such permits in the next six months.[116]

For the other milestone dates after the Permitting Completion Deadline, but prior to the Initial Delivery Date, such as financing, notice to proceed on the Engineering Procurement and Construction ("EPC") contract, delivery of generators to the site, and energization of project, if

[116] Term Sheet at 5.

such milestones were not met within 60 days of the milestone deadline date for reasons not due to Force Majeure, Delmarva proposes that an Event of Default would arise. Upon the occurrence of such an Event of Default, Delmarva would have the right to terminate the PPA and retain the full amount of the Development Period Security as Liquidated Damages.[117]

Delmarva would grant extensions in the Guaranteed Initial Delivery Date of up to 12 months due to Force Majeure delays. In addition, a further 12-month delay in the Guaranteed Initial Delivery Date is allowed provided that Delay Damages are paid during the additional 12 month period. After all allowed delays, Delmarva proposes that the Buyer may elect to terminate and get a Termination Fee, which is based on $100/kW.[118] This is in addition to the Delay Damages described below in subparagraph (b).

In addition, Delmarva proposes that failure to meet milestones during the construction period would result in forfeiture of specified amounts of security (which amounts are not identified in the Term Sheet).[119] Any security withdrawn would be required to be replenished.[120]

With respect to its own defaults in the pre-operational period, Delmarva takes the position that the Buyer will pay a termination payment limited to $50/kW.

In reaction, NRG asks that the permitting milestone be at least 24 months, with Force Majeure extensions (at pages 25-26). Other than the permitting milestone, the only milestones should be financing and commercial operation in NRG's view (at page 29). NRG also argues that the Buyer's limitation of damages for pre-Initial Delivery Date defaults to $50/kW would likely make a Project non-financeable. In such a case, NRG says that the appropriate damage amount should be the recovery of the Seller's expenses plus a breakage or termination fee to be paid by the Buyer (at page 26). Finally, NRG comments that the RFP does not appear to require a Delmarva affiliate to post security (at page 23).

Bluewater Wind suggested an even longer permitting milestone at 36 months. If there were a failure to obtain permits, Buyer would have a termination right but Liquidated Damages in Bluewater's view would be limited to $10/kW. Similar to the Delmarva position, Bluewater would give the Seller the right to a six-month extension of the permitting milestone, but the added exposure would result in a total Liquidated Damages amount upon any subsequent permit failure of $15/kW.

In the Independent Consultant's experience, setting fixed permitting and other milestones without regard to the nature and location of a Project is an unrealistic exercise. As a result, the Independent Consultant recommends that bidders should be allowed to bid milestone dates which are consistent with the schedule appropriate for their Projects. The overall schedule, however, would need to fall within the "not later than" deadlines in the RFP, taking into account the possibility of allowed extensions of the Guaranteed Initial Delivery Date ("GIDD").

[117] See Term Sheet at 6.
[118] Term Sheet at 6. The Term Sheet at page 10 describes this remedy as the Termination Payment which is said to equal the "undrawn portion of the Development Period Security."
[119] See Proposed RFP at 21.
[120] Id.

Delmarva, in its comments on the Initial Report, expressed willingness to work with bidders in setting milestones that worked backwards from the GIDD, which itself would be a fixed duration, chosen by the bidder, after the Effective Date (p. 34). Delmarva continued to look for a two-step permitting deadline, with the second deadline, at the Seller's option, six months after the first.

The Independent Consultant agrees with Delmarva that the GIDD deadline should be subject to a maximum 12-month Force Majeure extension. In our initial report, we recommended that the Force Majeure definition be expanded to include the possibility of delays both in the Effective Date (due to an appeal of the Commission order) and in the Permitting Completion Deadline (where a limit could be placed on the aggregate number of months of permit delay, such as 6 months). In its comments, Delmarva argued against Force Majeure extension of either the permit milestones or the Effective Date (p. 34). In light of the consensus that bidders will set the initial Permitting Completion Deadline and that a second deadline, six months after the first, is an available option, we agree that a short Force Majeure extension of the permit deadline is not necessary. Furthermore, we believe that a definition of the Effective Date which depends upon the occurrence of a final, non-appealable Regulatory Approval will bring Delmarva's position and our own into accord.

The Independent Consultant again concurs with Delmarva that the Guaranteed Initial Delivery Date should, in addition, be subject to a further maximum 12-month delay, during which Delay Damages would be payable.

The Independent Consultant views Delmarva's attempt to limit its damages to $50/kW during the pre-IDD portion of the term of the PPA as unworkable. It is conventional wisdom that such damage limitations make financing entities unwilling to risk amounts of capital which may be significantly in excess of the damage recovery. As a result, common industry practice provides that if the Buyer defaults after the commencement of construction, the Buyer should pay all direct damages as required by law. For early defaults, benefit of the bargain damages, which are the common legal remedy, are not always needed, provided that the non-defaulting party is fully compensated for its losses. In this latter regard, the Independent Consultant believes that the Buyer's damages due to any default prior to the commencement of construction can be limited to the reimbursement of Seller's costs plus a breakage fee without adversely affecting the ability of the Seller to finance. The Independent Consultant recommends that the breakage fee could either be set at an appropriate level, such as $10/kW, or be an amount based on a number or formula proposed by bidders.

In its comments to the Initial Report, Delmarva countered our objections to its early termination $50/kW liability limit by taking the position that a provision for the recovery of all direct damages would be acceptable to it if the provision were bilaterally imposed on both parties (p. 34). Delmarva then argued that its proposed liquidated damage provision is sufficient to support financing. Delmarva finally offered to make up any shortfall between liquidated damages and the amount of construction draws (presumably as of the date of termination) (p. 35).

For financing reasons, we continue to advance our original recommendations. In our view, it is sufficient for financing purposes to compensate the Seller for actual losses, and a modest breakage fee, when a Buyer defaults before construction. At this point, the Seller's incurred costs and exposures are relatively small compared to the hundreds of millions of dollars that are required for construction of plants likely to be proposed in response to the RFP. However, we believe it is an impediment to financing either to try to guess such pre-construction losses with size-related liquidation formulae or to impose a size-related limitation after construction. At such time, compensating a Seller for only up to the amounts of its loan draws likely leaves numerous Project liabilities for the innocent party to absorb. Direct damages for default prior to commercial operation for sellers with respect to new generation to be built is at odds with standard industry practice, would create major financing problems, and does not take into consideration that it is the seller that has the responsibility of investing hundreds of millions of dollars in new capital to perform under the contract.

B Delay Damages

Delmarva has proposed that for each day of delay past the Guaranteed Initial Delivery Date, Seller shall pay $0.2333/kW per day or $7/kW per month in Liquidated Damages ("Delay Damages") up to maximum of $85.15/kW. Delay Damages would not apply, as indicated above, if Force Majeure caused the subject delays (up to 12 months in aggregate). Delmarva has also indicated that failure to meet milestone dates during the construction period may result in forfeiture of specified amounts of security (which amounts are not identified in the Term Sheet).[121] As with other Delay Damages, any security withdrawn to pay these construction period damages would be required to be replenished.[122] Neither the proposed Delay Damages nor the amount received attention in the filed comments.

In the Independent Consultant's experience, Delay Damages are a conventional provision in PPAs to compensate Buyers for the effects of delay and to provide Sellers, at a price, relief from termination where progress is occurring but not at the hoped for pace. Since delays do have consequences to Buyers, and Sellers often do need some relief from planning schedules set in advance of their actual development efforts, the Independent Consultant endorses the concept of Delay Damages.

With respect to the proposed amount of $7/kW per month or $0.2333/kW per day for up to 12 months, this amount from our experience is somewhat high, but not unusually high.[123] Hence, in our view, it is not commercially unreasonable.

[121] See Proposed RFP at 21.
[122] Id.
[123] See discussion at Section V.vi.a of this report and n. 48.

C Initial Delivery Date Requirements

In its proposed terms, Delmarva stipulates that, in order to achieve "Commercial Operation," Seller must satisfy 95% of Contract Capacity. Various other demonstrations must be made, as further identified in the Term Sheet,[124] including fuel supply and transmission services agreements and available allowances and offsets satisfactory to Delmarva. It does not appear that comments were received on these requirements.

The Act instructs the Agencies and Delmarva to encourage innovation. For financing purposes, the ability of the PPA Seller to meet realistic requirements for commercial operation is considered to be critical. Termination consequences flow from failures to achieve deadlines for commercial operation. Based on the foregoing, and an emerging industry practice, the Independent Consultant believes that the 95% standard may need to be relaxed for newer technologies. In such cases, bidders should be allowed to bid initial percentages and standards for meeting the Initial Delivery Date that are supported by emerging industry standards. To implement this flexibility, in our mark-up to Delmarva's term sheet, we proposed that, for less commercially established technologies, such as IGCC, the Seller should be allowed to propose, subject to Delmarva's approval, a percentage lower than 95% if consistent with the definitions of "Substantial Completion" and "Facility Acceptance" in the Seller's anticipated construction and/or financing agreements, subject to Delmarva's approval.

In response to the Initial Report, Delmarva argued that it requires certainty in the amount of capacity contracted or would be forced to over-subscribe for capacity if a standard less than 95% were allowed (p. 35). In addition, Delmarva objected to the unexplained deletion of the condition to the Initial Delivery Date that required bidders to hold all emission allowances, credits and offsets to the extent required to operate at the maximum capacity bid (p. 35).

We continue to believe, consistent with the Act, that innovative technologies, such as IGCC, should be allowed some initial flexibility in demonstrating Contract Capacity for purposes of meeting the Initial Delivery Date. For such technologies, a 95% requirement may not be consistent with market realities. Since the risk of termination for overly strict pre-conditions to the IDD will stifle participation in the bidding, we again recommend that bidders with innovative technologies be allowed to bid lower numbers, subject to the requirement that they support any number less than 95% with market information.

Our reasoning for the deletion of the requirement that the Seller have, as of the IDD, all emission allowances, offsets and credits required for operation of the Project is that it is too vague. A seller may need to acquire allowances and the amount needed is based on actual production. We would support inclusion of such a requirement based on a reasonable time period and expected production.

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[124] Term Sheet at 4.

D Events of Default/Remedies

With respect to delivery performance, Delmarva does not consider unavailability of the Project as an excuse for any failure to deliver Products.[125] When any Product is undelivered without excuse as and when required under the PPA, the Seller is in "Default."[126] In such a case, it appears that the Seller also has caused an "Event of Default" and the Seller will be obligated to pay cost of cover damages.[127] In Delmarva's view, Force Majeure does not excuse Product delivery failures.[128]

Additionally, Delmarva has proposed that an Event of Default exists if (a) the UCAP rating of the Project is below 90% of the Monthly Contract Capacity for a period of six consecutive months for any reason not due to Force Majeure; or (b) an Event of Force Majeure causes UCAP to be below 90% for 12 consecutive months. Furthermore, if a Product delivery failure occurs five times in a calendar year, Delmarva treats such repetitive failures as an Event of Default.[129] In such a case, and when any other Event of Default occurs, Buyer can terminate and collect the Termination Payment. The Termination Payment will be all Settlement Amounts netted into a single amount, where Settlement Amount, and the related Gains, Losses and Costs, are all given the meanings defined in EEI Master Agreement.[130]

It is also part of Delmarva's proposal that the non-defaulting party can set off the amount(s) it is owed by an affiliate of the defaulting party, as described more fully in Subparagraph (e), next following.

Another area of potential default in Delmarva's view is future Resource Adequacy Requirements. If the Seller fails to comply with Resource Adequacy Requirements, if either the DPSC or PJM develops a Resource Adequacy requirement, the Seller is obligated to take such measures as are needed to qualify the Project.[131]

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NRG's comments in reaction to Delmarva's default and remedy proposals include the following: (a) the Seller should not be required to comply with new Resource Adequacy requirements, especially those imposed by the Commission (at pages 24-25); (b) set off rights regarding affiliates are not acceptable and should be eliminated since such rights do not work in the project finance context (at page 27); (c) Sellers should have no obligation to deliver "firm power" (at page 30); and (d) the proposed right to terminate for failure to deliver five times in year discriminates against new technologies and should be dropped (at page 27). Bluewater Wind also argues that firm power and other capacity-related performance requirements are onerous and

[125] "The unavailability of a Unit dispatched within the operational constraints of that Unit will not excuse Seller's obligation to deliver any Product as otherwise required under [the PPA]." Term Sheet at page 6.
[126] Term Sheet at 9.
[127] Term Sheet at 9, 10. In its comments to the Initial Report (p. 35), Delmarva clarified its intention with respect to the failure to delivery any Product. For the general failure to deliver Product, cover damages were the exclusive remedy sought; Delmarva did not propose that the delivery breach be treated as an Event of Default resulting in a termination right for the Buyer.
[128] Term Sheet at 12.
[129] Term Sheet at 10.
[130] Term Sheet at 10-11.
[131] Term Sheet at 4.

inappropriate for wind projects. For wind projects, more appropriate measures of performance would be failures to deliver some percentage, such as 50%, of expected "[energy]" in a 12 month period (at page 53).

The Independent Consultant disfavors Delmarva's proposal for "Firm" energy and other Product delivery requirements.[132] Consistent with industry practices, bidders should have the right to bid unit contingent power and should not be required under the pricing and default provisions of the PPA to treat any bid Project as the source of "Firm" power. In this regard, it is the Independent Consultant's view that availability should be used as a factor adjusting price, but no specific availability failure should be treated as a failure in performance. Also, the Independent Consultant does not view five outages in a year as a termination event. Consistent with the uniform industry treatment of a unit contingent PPA, no Product delivery failure at any specific time should alone result in a termination event.

In its comments to the Initial Report, Delmarva reiterates its position that Product requirements include "Firm" energy and objects to any change that would prevent it from recovering cover damages when "Firm" energy is not delivered (p. 35). For reasons previously stated, unit contingent power with price adjustment provisions in the nature of liquidated damages is appropriate Product under the RFP and in all likelihood the only appropriate product for prospective bidders.. As a result, for unit power, non-delivery at any point in time is not itself appropriate as an event of default.

Notwithstanding the foregoing, in the Independent Consultant's experience, termination events do arise in PPAs for aggregate poor performance over suitable time frames. Such time period performance standards should vary based on technology. In our revisions to the Term Sheet, we suggested replacing Delmarva's time period failure (failure to maintain UCAP of at least 90% for six consecutive months for reasons not attributable to Force Majeure), with an event of default if the Equivalent Availability Factor was less than 60% for twelve consecutive months.

In its responding comments, Delmarva presses for the use of UCAP as the appropriate measure of performance and objects to the deletion of the UCAP event of default (pp. 18, 36). We note that both capacity and availability testing over suitable time frames are conventionally used in PPAs. However, we do think that events of default for emerging technologies should be implemented with due care. In this regard, we recommend flexibility—it is acceptable for the form of PPA to include UCAP requirements, as Delmarva prefers, but this event of default definition should not be a non-negotiable provision. For a particular emerging technology, bidders should be free to propose different provisions.

With respect to any new PJM Resource Adequacy ("RA") requirement, the Independent Consultant has the following recommendation: the Seller should be obligated to comply with the requirement if it is feasible to do so; however, the rule should be that the PPA Seller should not be required to incur any material increase in operating or capital costs, or any material decrease in revenues, in order to meet such RA requirement. If such material changes would be required, the PPA Buyer should have the right and option to hold the Seller harmless in order to assure

[132] See Section IV D (ii) above.

compliance with the RA requirement. In the event that the parties disagree on the amount needed to keep the Seller in the same financial position, the matter would be resolved in accordance with the contract dispute resolution mechanism. In the view of the Independent Consultant, the foregoing treatment of the RA requirement is balanced. It would not adversely affect the ability of the Seller to finance the PPA and it would allow the Buyer to comply with such requirements, although an increased charge may sometimes result.

In response to our comments in the preceding paragraph, Delmarva took exception, based primarily on the view that some threshold amount should be imposed on the Seller as a cost of complying with the "wholly foreseeable" prospect of new RA requirements. (pp. 36-37). Delmarva states, "Delmarva is willing to compensate a seller for its incremental out-of-pocket costs it would not have incurred but for its obligation to comply with the RA requirement" (p. 36). We interpret the Delmarva response as largely in accord with our view that a RA compliance obligation exist, provided that compliance is feasible and that incremental costs be assigned appropriately. We do not find the assignment of a specified threshold amount of new RA compliance costs to bidders to be at variance with our views, provided that the RFP sets forth the amount clearly. Again, this would not be a non-negotiable provision.

It has been the experience of the Independent Consultant that the payment by the non-defaulting party to the defaulting party of the non-defaulting party's Gains, as required after calculation of the Settlement Amount by the applicable EEI Master Power Agreement, may create financing problems for PPA Sellers. After the Buyer's default, such a Seller would be left, in this case, in a market with higher prices but without any long term contract. Without any long term contract, a Seller may have trouble finding financing sources in order to meet the termination obligation to pay the defaulting Buyer the Seller's Gains (the capitalized value of the difference between such higher market prices and the contract price). It is accordingly recommended that EEI treatment of Gains be eliminated in the form contract to be filed by Delmarva. The non-defaulting party should be allowed to retain Gains. In the Independent Consultant's experience, this has been standard industry practice for long term PPAs.

For financing purposes, the Independent Consultant recommends additional changes to the definitions of Events of Default as formulated by Delmarva. In this regard, failures to post Development Security, meet Credit requirements, or comply with any Resource Adequacy requirement should be subject to notice and opportunity to cure, similar to the blanket default provision, prior to maturing into an Event of Default. Also, it should be clarified that misrepresentations are subject to a 30-day cure period.

We addressed these matters in more detail in our mark-up to Delmarva's Term Sheet.

In its comments, Delmarva took exception, arguing that the requirements for posting of both Development Security and Credit would be well known and necessary to protect Delmarva from exposure to harm at critical times (pp. 36, 37). We agree such posting requirements are important. We foresee only limited instances where notice would be called for, and only brief three to five day cure periods consistent with standard commercial practices. Like well known and important payment deadlines, deadlines for security or credit to be renewed or replenished can sometimes be overlooked due to administrative errors. Termination is not an appropriate consequence if such obligations can be quickly cured once attention is brought to the failure. These matters should be addressed in the standard PPA.

E Set-off

Delmarva proposes that the non-defaulting party shall have the right to set off against any amounts owed to the defaulting party by the non-defaulting party or any of its affiliates under the PPA or otherwise any amounts payable by the defaulting party to the non-defaulting party or any of its affiliates under the PPA or otherwise.[133] As indicated in Subparagraph (d) above, NRG argued that set off rights regarding affiliates are not acceptable and should be eliminated since such rights do not work in the project finance context (at page 27). In the Independent Consultant's experience, affiliate set-off provisions impair the ability of the Seller to finance and should for that reason alone be dropped.

In its comments, Delmarva disagrees that lenders object to set-offs in the context that the term is being used by Delmarva: "allowing a non-defaulting party to set off amounts owed to a defaulting party" (p. 37). Actual contract language may result in agreement on this topic. Since we see ambiguity in Delmarva's formulation, we re-emphasize our concern: any amounts payable by a defaulting party to the non-defaulting party's affiliates should not be offset against amounts payable to the defaulting party by the non-defaulting party under the PPA. For example, if the Seller is in default, but is owed amounts for outstanding invoices for power actually delivered, the Buyer should not offset against these power bills amounts due from the Seller to any affiliate of the Buyer under some other arrangement between the Seller and any such affiliate of the Buyer.

F Change in Law

In the Delmarva proposal, the Seller bears all risks of complying with all applicable requirements of law, PJM and NERC, whether imposed pursuant to existing law or pursuant to changes enacted or implemented during the Term of the PPA, including, without limitation, such changes in environmental law.[134] In response, NRG argued that future environmental compliance costs should be borne equitably by the parties (at pages 27-28).

In its Initial Report, Independent Consultant recommended that in the event that a change in law occurs which imposes future environmental compliance costs in the form of a Btu or carbon tax, Sellers should be allowed to treat the tax as a "pass-through" addition to the cost of energy. The Independent Consultant acknowledged that standard industry practice in long term PPAs to date makes future environmental compliance costs that are not in the nature of a tax, pursuant to existing or future laws and regulations, a Seller responsibility. However, with respect to future compliance costs in the form of a new Btu or carbon tax of general applicability in the industry, it is common for those change-in-law costs to be shifted away from the Seller. Our recommendations in our initial report were based on this distinction, with environmental costs

[133] Term Sheet at 11.
[134] Term Sheet at 13.

due to change in law that are not in the nature of a tax of general applicability to be risks borne by the Seller.

In response to the Initial Report's recommendation, Messrs. Jeremy Firestone and Willett Kempton opposed the pass-through of Btu or carbon taxes (p. 4). Delmarva thought that present or future carbon tax compliance costs could be treated either as a Seller responsibility or as a pass-through cost of energy, subject in the latter case to Delmarva's ability to recover the additional costs in rates (at p. 37). NRG took exception to the limitation in the Initial Report of the pass-through mechanism to only future Btu or carbon tax change in law, describing the limitation as specifically at cross purposes to the Act (p. 11). NRG claimed that the Independent Consultant erred in not endorsing a broader mechanism equitably adjusting the contract capacity price for capital costs incurred as a result of any change in law or regulation (p. 12). In this regard, the NRG position did not appear limited to environmental changes in law.

After considering input from the various commenters, we propose a change to our recommendation on this matter. We would provide bidders with two options. A bidder could assume the change-in-law risk in its entirety and its bid would be so treated in the economic evaluation. Alternatively, in the event that there is a future btu tax or carbon tax of general applicability, a bidder could seek to recover only the amount of a btu or carbon tax attributable to the average cost that would be assessed on generators in the relevant market based on average emissions. Specifically, we would limit the ability of the seller to recover costs imposed on it by such tax only to the extent of the amount of tax per MWh attributable to the average level of emissions from all facilities in the PJM Classic market. In this manner, a bidder must accept the risk that it would contribute to greenhouse gas emissions to an extent greater than the market norm. From an economic standpoint this is reasonable because market prices would be expected to rise based on average emissions and it is reasonable for a Seller to be at risk for the excess amount. We note that a bidder that takes the entire risk and a bidder with no emissions will score better in the price and price stability categories, other things being equal.

We continue to have problems with NRG's request for a broader price adjustment provision associated with changes in environmental laws or regulations that may necessitate capital expenditures or increased operating costs in order to comply. Initially, it is reasonable for a Seller under a long-term contract to assume these risks and to incorporate the risk allocation in its bid price. This risk can also be addressed in connection with the contract term (bidders may bid 10 to 25 year contract terms). Furthermore, it would be extremely difficult to structure and implement the type of contract provision for which NRG is advocating. For these reasons, we decline to recommend a more open-ended price adjustment provision associated with change in law.

G Dispute Resolution

Delmarva proposes that all disputes be referred to the Commission for resolution.[135] NRG commented that the parties should have the option to resolve disputes under the PPA by arbitration or litigation.

The Independent Consultant does not view industry practice as uniform with respect to how disputes are resolved. Long-term PPAs will generally resolve disputes by arbitration or by litigation or by some combination of these forms of dispute resolution. It is, however, rare that resolution requires resort to the state utility commission. Commissions are primarily engaged in rate matters and other strategic utility matters. In light of their duties to protect ratepayer interests, they may not be viewed by the independent power industry as completely neutral in the resolution of contract disputes that could result in higher power costs to ratepayers. As a result, the Independent Consultant does not recommend that disputes be referred to the Commission for resolution. Delmarva should be given the option in the filed form of contract to resolve disputes under the PPA by arbitration or litigation.

In its comments, Delmarva argues that the Commission is charged with protecting the public interest and in addition, is the most knowledgeable party to address contract problems. Further, Delmarva suggests that Commission resolution would offer "one-stop" treatment, i.e., it could resolve the problem and if PPA costs increased as a result, it could approve the increase in rates at the same or a related time. While rate recovery is a legitimate concern of Delmarva, we continue to view the nexus between dispute resolution and rate setting as problematic to bidders and being beyond the normal scope of public service commission responsibilities.

H Other Issues

Delmarva has proposed that the Seller should pay Buyer's reasonable costs associated with review, negotiation, execution and delivery of any documents associated with consenting to assignments, including attorneys' fees. In addition, Delmarva proposes that the Seller should pay the amount of all expenses including reasonable attorneys' fees and expenses, paid or incurred by Buyer (i) after any of the obligations of Seller are not paid or performed when due; (ii) after a default or an Event of Default shall occur; (iii) in exercising or enforcing or consulting with its counsel regarding any of its rights under the PPA or under law.[136] NRG in this regard argues that the Seller should not be required to pay for the Buyer's legal costs to effectuate an assignment (at page 31). On other issues, NRG had additional comments as follows: (a) the Force Majeure clause should be revised to make it more equitable (at page 29); and (b) the assignment clause should be changed to avoid any implication that a future change of control of the Seller requires the Buyer's approval (at pages 30-31).

On the latter point, the Independent Consultant does agree with NRG that the assignment clause language should be clarified, to the extent necessary, to assure that future changes of control with respect to the Seller would not involve the Buyer's consent. Delmarva strongly resisted our

[135] Term Sheet at 14.
[136] Term Sheet at 15.

suggested clarification, stating that the continuity of the identity of the Seller is critical to the PPA and that it is "wholly industry standard" to require the Buyer's consent if control is transferred (p. 38).

While we do not agree that there is a clear industry standard on this point, we are agreeable with Delmarva including in the standard PPA reasonable "change of control" language which satisfies its concerns; however, such a provisions would not be one that is "non-negotiable." Specifying the standard that would govern the granting of consent may be helpful, such as comparable creditworthiness and/or comparable development expertise (if relevant for the state of development of the project), with consent not to be unreasonably withheld. We can foresee circumstances that would make such a consent requirement an unnecessary constraint on normal commercial transactions. Hence, we believe this should not be a "non-negotiable" provision..

With respect to the contract language controlling consents to financing assignments, we offered our language suggestions in a mark-up to the Term Sheet and Delmarva appropriately commented how language, such as ours, dependent on "materiality" invites differing viewpoints (p. 38). Delmarva's alternative approach—to offer a form of consent—is a common and workable approach. PPA Buyers frequently fashion consent forms acceptable to financing entities and we await their form.

The Independent Consultant views the reimbursement language of Delmarva as overly broad in scope and outside conventional practice. In the Independent Consultant's view, the language requiring the payment of the Buyer's expenses whenever the Buyer consults with its counsel regarding any of its rights should be deleted. Furthermore, other expense reimbursement language needs to be more tightly drafted to avoid covering normal transactional costs of the contract parties. After review of Delmarva's response to the above suggestions (p. 38), we believe accord exists on these drafting issues.

The Independent Consultant recommends that the Force Majeure clause should be revised to clarify what types of risks beyond the control of the Seller are allowable and what are the applicable time limits for which a claimed Force Majeure could apply. We addressed this in our mark-up to Delmarva's proposed Term Sheet and Delmarva was willing to accept our suggested modifications (p. 38), subject to the understanding that a claim of Force Majeure would not extend the milestone for obtaining permits prior to the Initial Delivery Date. As indicated above, we now concur with Delmarva that the milestone to obtain permits may not be delayed due to a claim of Force Majeure.

VIII Conclusions

The Independent Consultant, retained by the State Agencies pursuant to the Act, has reviewed Delmarva's Proposed RFP and the comments of the various participants in this proceeding. For the reasons set forth in this report, we have recommended a substantial number of changes, which are specified in this report.

Appendix A

EXPERIENCE AND QUALIFICATIONS OF THE INDEPENDENT CONSULTANT

The Independent Consultant is a team of New Energy Opportunities, Inc. (NEO) and its subcontractors, Merrimack Energy Group, Inc., La Capra Associates, Inc., and Edward Selgrade, Esq. Members of the consulting team have assisted utilities and other power purchasers and public agencies in the development and evaluation of competitive bidding programs over the past 15 years.

New Energy Opportunities

NEO is a consulting firm with a focus on the procurement and sale of energy, capacity and other products from electric generation facilities. NEO and its principal, Barry Sheingold, have organized procurements and drafted Requests for Proposals for both private and public clients, resulting in numerous closed transactions of different types. This work has included RFP design, formulation of evaluation criteria, drafting term sheets and standard contracts, performing economic and technical bid evaluations, negotiation assistance, conducting surveys and providing testimony on procurement-related issues. NEO has assisted buyers in preparing RFPs as well as sellers in developing proposals in response to RFPs. Projects have ranged in size from 1 MW to 450 MW; technologies have included wind energy, natural gas combined cycle, biomass, and landfill gas.

Barry Sheingold has over 15 years of experience in the design and structure of long-term contracts for the purchase and sale of electric power, especially to support the financing of new generation facilities, for designing competitive procurements and in evaluating bids. In 2003, Mr. Sheingold provided the conceptual and detailed design, assisted by Wayne Oliver of Merrimack Energy, for the Massachusetts Technology Collaborative's competitive bidding program for the procurement of renewable energy certificates, and options on renewable energy certificates, under long-term contracts. The purpose of this program—the Massachusetts Green Power Partnership—is to provide financing support for new generation facilities in a competitive, deregulated market where long-term contracts are very difficult for developers to obtain. In addition, Mr. Sheingold was the principal consultant in developing the economic evaluation criteria, evaluating the bids from an economic perspective, and advising on contract negotiations with the winning bidders. He has collaborated with both Merrimack Energy and La Capra Associates, who have also provided services for this program, which has thus far resulted in two bidding rounds, eight executed contracts and five projects that are either in construction or in operation. He has also advised the New York State Energy Research and Development Authority in its program of procuring generation attributes from renewable energy projects under long-term contracts in implementing the New York Renewable Portfolio Standard, again working with La Capra Associates.

In recent years, Mr. Sheingold helped develop and implement a competitive procurement process for a private client, resulting in a 12-year power purchase contract with a creditworthy supplier and has participated in several other competitive procurements in a variety of capacities—assistance in bid evaluation for potential buyers (Portland General Electric and Town of Fairhaven), providing expert testimony (Hydro Quebec Distribution), development and implementation of a "reverse RFP" for a generator, and supplying advice to a bidder in a long-term capacity procurement RFP.

Mr. Sheingold has many years of relevant experience, both from a commercial and legal perspective. As Senior Counsel with Delmarva Power & Light in the 1980s, he helped in developing the company's first competitive power procurement under long-term purchase contracts. The RFP was issued after Mr. Sheingold left the company in early 1989 to take the position of General Counsel and Vice President at Citizens Power, the nation's first independent electric power marketing company, where he played an important role in pioneering market-based ratemaking for power marketers (and later independent power producers) with the 1989 *Citizens Power* decision at the Federal Energy Regulatory Commission. At Citizens Power, Mr. Sheingold specialized in long-term contracts between generators and utilities and the restructuring of those contracts, working for both buyers and sellers and for Citizens Power acting as a principal. He advised clients in a variety of competitive power procurements in Massachusetts, Oregon, New Jersey, Delaware, Indiana, California, Maryland, Nevada and elsewhere. In 1994, Mr. Sheingold was promoted to Senior Vice President, where he was responsible for a variety of business development activities. He founded NEO in 2000, where he has assisted public and private clients in structuring long-term power contracts and procurements to support financing of new generation facilities.

Merrimack Energy

Wayne Oliver, Principal of Merrimack Energy, has served in the role of independent evaluator on nearly 20 different competitive solicitations for the procurement of power supplies throughout the United States and Canada involving a range of resource options. Merrimack has also been at the forefront in working with market participants in undertaking competitive bidding and power procurement assignments and is well versed in industry standards associated with effective bidding processes. Merrimack is very experienced in understanding the characteristics of effective competitive bidding programs, the price and non-price evaluation criteria generally used, the models employed in assessing bids, assessment of key risk factors and the role of consultants in the process through numerous similar experiences and projects. Wayne Oliver is very familiar with a wide range of generating technologies, including pulverized coal, integrated coal gasification combined cycle (IGCC) facilities, gas-fired combined cycle and combustion turbines. Merrimack Energy is currently serving or has recently served as independent evaluator or monitor on three major competitive bidding assignments. Mr. Oliver formerly served as Independent Evaluator for Delmarva's 1991 RFP for power supplies.

Wayne Oliver has been involved in over 25 major competitive bidding projects and has reviewed hundreds of power supply proposals. In addition, he has served as the Independent Evaluator in nearly 20 separate solicitations. Through these assignments, Merrimack is well aware of current industry standards associated with the evaluation criteria applied in competitive solicitations, the quantitative methodologies used by utilities to evaluate bids, current contract issues, and recent initiatives in the bidding area which have been designed to respond to the current financial situation in the power industry.

Merrimack's experience includes:

- Design of traditional supply-side, options, renewable resources, and demand-side programs for both long-term and short-term resources. Merrimack's work has included design of the RFP and response package, the evaluation system, and assistance with the business and legal aspects of the power contracts.
- Project management on behalf of power buyers regarding the review and evaluation of proposals. In this role, Merrimack has developed evaluation procedures and processes to ensure consistent and effective bid evaluation. In some cases, Merrimack has conducted independent evaluation of the bids received to ensure the results of the evaluation are consistent.
- Independent third-party evaluator monitoring, overseeing, and in some cases auditing the proposal evaluation and selection process undertaken by the power buyer. In this role, Merrimack has independently evaluated proposals from a price and non-price perspective and has overseen the selection process in response to regulatory requirements and/or in cases in which the utility or its affiliates was also a bidder.
- Preparation of an independent report or analysis of the solicitation and evaluation process for submission to the state/provincial regulatory commission regarding the fairness and equity of the process and to avoid undue litigation regarding the evaluation and selection process.
- Developing and/or utilizing a range of power project evaluation methodologies for RFPs and other purposes including production cost analysis, portfolio evaluation methodologies, real levelized cost models, and option pricing models.

Wayne Oliver was formerly founder of Reed Consulting Group. Mr. Oliver managed Reed's electric utility practice, including managing the vast majority of Reed's competitive bidding assignments on behalf of electric and gas utilities. In recent years, Mr. Oliver has been the Project Manager for Merrimack Energy's assignments for the Utah Public Service Commission, Southwestern Electric Power Company, Public Service Company of Oklahoma, Hydro-Quebec, Portland General Electric, BC Hydro, and Hawaiian Electric in competitive power procurement and related matters. He has testified on behalf of a number of utilities, independent power producers, and public agencies before state and federal regulatory Commissions on issues pertaining to power procurement.

La Capra Associates

La Capra is an employee-owned, Boston-based consulting firm specializing in the electricity power industry. Founded 25 years ago, La Capra Associates has provided strategic planning and procurement advice to senior managers and policy makers along with expert, technical analysis to support policy, investment, and operational decisions. The firm provides consulting services regarding energy planning and risk management, power market analysis, ratemaking, and regulatory policy in the electric industry. La Capra Associates has a thorough understanding of electric power systems and the costs and risks related to production of electricity from both renewable and non-renewable generation. Jonathan Winer and Richard Hahn, both highly experienced consultants with years of applicable experience, lead La Capra Associates' participation in this project.

La Capra Associates provides services to the full range of organizations involved with energy markets – public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations. Over the years, La Capra Associates has provided services in a variety of important areas in the industry, including areas such as marginal cost pricing, integrated resource planning, competitive power supply procurement, and demand-side programs.

The firm's technical skills include forecasting models and methods, economics, finance, law, management, planning, pricing, engineering, procurement, and contracts. The firm also offers skills in market rules, regulations, policy, and negotiations; La Capra Associates regularly provides services ranging from broad policy development, to analysis of major investments, to short-term planning and operations. La Capra Associates' work has frequently led to presentation of expert testimony or opinion before state or federal regulatory agencies, financial institutions, and corporate management and boards.

La Capra Associates' experience in power procurement includes on-going transactions advisory services regarding preferred strategies for the purchase and sale of power in ISO-New England, New York and PJM. In this regard, La Capra Associates has advised on a large number of system and unit power contracts. This work included advising the California Bureau of State Audits in connection with its audit of the transactions of the California Water Resources Board following the collapse of the California market. La Capra Associates' procurement engagements also include work for state regulators and industrial customer groups concerning power transactions and hedging procedures of large utility systems in Pennsylvania, Oklahoma, Wyoming, Nevada, and Arizona.

Edward L. Selgrade, Esquire

Edward Selgrade provides legal advice to the Independent Consultant. He is an independent attorney and a former Commissioner with the Massachusetts Department of Public Utilities who has specialized over the past 22 years in power contracts, environmental permitting and lenders due diligence for developers and purchasers from competitive power projects.

Mr. Selgrade is an independent attorney with three degrees in Mathematics and Physics and a law degree from Harvard University. Mr. Selgrade has worked with Mr. Oliver on a number of competitive bidding assignments in the power contracting and environmental assessment areas. He has also worked with Mr. Sheingold for clients involving commercial contracts for wind energy projects. Over a two-year period ending in 2005, he served as an arbitrator under the auspices of the International Court of Arbitration on one of the largest, if not the largest, power plant construction arbitration in history involving a.775 MW natural gas-fired power plant Mr. Selgrade has also represented several power project developers in the permitting and regulatory aspects of gas and coal power projects, totaling 1,350 MW.

Appendix B

SECTION OF THE ELECTRIC UTLITY RETAIL CUSTOMER SUPPLY ACT OF 2006 APPLICABLE TO RFP PROCESS—Section 6, Replacing 26 Del C. § 1007(d)

(d) As part of the initial IRP process, to immediately attempt to stabilize the long-term outlook for Standard Offer Supply in the DP&L service territory, DP&L shall file on or before August 1, 2006 a proposal to obtain long-term contracts. The application shall contain a proposed form of request for proposals ("RFP") for the construction of new generation resources within Delaware for the purpose of serving its customers taking Standard Offer Service. Such proposed RFP shall include a proposed form of output contract which shall include capacity and energy and may include ancillary electric products and environmental attributes between the electric distribution company and developers of new generation facilities, which contract shall have a term of no less than ten (10) years and no more than twenty-five (25) years. Such RFP shall also set forth proposed selection criteria based on the cost-effectiveness of the project in producing energy price stability, reductions in environmental impact, benefits of adopting new and emerging technology, siting feasibility and terms and conditions concerning the sale of energy output from such facilities.

(1) The Commission and Energy Office may approve or modify the elements of the RFP prior to its issuance. The Commission and Energy Office shall ensure that each RFP elicits and recognizes the value of: a. proposals that utilize new or innovative baseload technologies, b. proposals that provide long-term environmental benefits to the state, c. proposals that have existing fuel and transmission infrastructure, d. proposals that promote fuel diversity, e. proposals that support or improve reliability, and f. proposals that utilize existing brownfield or industrial sites. Such RFP shall be issued no later than November 1, 2006. Proposals will be due no later than December 22, 2006.

(2) DP&L shall publish such request for proposals in one or more newspapers or periodicals with general circulation, as selected by the Commission, and shall post such request for proposals on its web site. The Commission, the Director of the Office of Management and Budget, the Controller General and the Energy Office shall retain the services of an independent third-party entity with expertise in the area of energy procurement at the expense of DP&L to oversee the development of the request for proposals and to assist them in their review of proposals pursuant to subpart (d)(3) of this section. Public service companies shall be eligible to participate in such RFP process through unregulated affiliated companies that meet the Commission's criteria to ensure that such affiliates are sufficiently financially and functionally separate from the regulated utility operations to prevent subsidization of the generation project by the regulated operations and to eliminate any other advantages from the affiliation with regulated operations.

(3) The Commission, the Director of the Office of Management and Budget, the Controller General and the Energy Office shall, on or before February 28, 2007, evaluate such

proposals and may determine to approve one or more of such proposals that result in the greatest long-term system benefits, including those identified in subpart (1), in the most cost-effective manner. Once one or more of the contracts have been finalized and approved by the Commission, the Director of the Office of Management and Budget, the Controller General and the Energy Office, then DP&L shall enter into such contract(s).

Appendix C

DELMARVA RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER LOADS
AND
RELATIONSHIP TO MAXIMUM CONTRACT SIZE

Delmarva Residential and Small Commercial Customer Loads and Relationship to Maximum Contract Size												
	Actual					**Projections**						
	2004-05	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Delmarva's Preliminary Forecast of RSCI Customers--Weather Adjusted												
Annual Peak Demand		922	933	958	980	996	1017	1037	1059	1085	1106	1124
Cumulative Growth (MW)			11	25	22	16	21	20	22	26	21	18
Annual Energy (GWH)	3,567	3,253	3,290	3,380	3,457	3,513	3,586	3,658	3,736	3,828	3,903	3,966
Increase		-8.8%	1.1%	2.7%	2.3%	1.6%	2.1%	2.0%	2.1%	2.5%	2.0%	1.6%
Increase (decrease) from 2004-05		-8.8%	-7.8%	-5.2%	-3.1%	-1.5%	0.5%	2.6%	4.7%	7.3%	9.4%	11.2%
Hypothetical Non-Weather Adjusted Increase from 2004-05 Levels												
Assumed rate of increase	2%											
Annual Energy (GWH)	3,567	3,638	3,711	3,785	3,861	3,938	4,017	4,097	4,179	4,263	4,348	4,435
POTENTIAL MAXIMUM CONTRACT SIZE												
Migration %	**None**											
MW	400	400	400	400	400	400	400	400	400	400	400	400
Capacity Factor	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Energy from plant (GWh)	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453
Energy % Delmarva estimate	69%	75%	75%	73%	71%	70%	68%	67%	66%	64%	63%	62%
Energy %, 2% increase per year	69%	67%	66%	65%	64%	62%	61%	60%	59%	58%	56%	55%
Migration %	**15%**											
MW	400	400	400	400	400	400	400	400	400	400	400	400
Capacity factor	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Energy from plant (GWh)	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453
Energy % Delmarva estimate	81%	89%	88%	85%	83%	82%	80%	79%	77%	75%	74%	73%
Energy %, 2% increase per year	81%	79%	78%	76%	75%	73%	72%	70%	69%	68%	66%	65%
MW	350	350	350	350	350	350	350	350	350	350	350	350
Capacity factor	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Energy from plant (GWh)	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146
Energy % Delmarva estimate	71%	78%	77%	75%	73%	72%	70%	69%	68%	66%	65%	64%
Energy %, 2% increase per year	71%	69%	68%	67%	65%	64%	63%	62%	60%	59%	58%	57%

APPENDIX D

PROJECTED DELMARVA RPS REC PURCHASE OBLIGATION PERTINENT TO RFP FOR STANDARD OFFER SERVICE

Projected Delmarva RPS Purchase Obligation for Standard Offer Service Pertinent to RFP						
	Delmarva Projected RSCI Load GWh	RPS %	Required RECs *	70% Limit	RECS for Purchase	Equivalent MW 40% Capacity Factor
2005	3,568					
2006	3,290					
2007	3,290	1%	32,900	23,030	20,000	6
2008	3,380	1.50%	50,700	35,490	33,000	9
2009	3,457	2%	69,140	48,398	45,000	13
2010	3,513	2.75%	96,608	67,625	65,000	19
2011	3,586	3.50%	125,510	87,857	85,000	24
2012	3,658	4.25%	155,465	108,826	105,000	30
2013	3,736	5%	186,800	130,760	125,000	36
2014	3,828	5.75%	220,110	154,077	150,000	43
2015	3,903	6.50%	253,695	177,587	175,000	50

* For purposes of these calculations, compliance year minimum percentages are applied to calendar year projections.

Appendix E

Appendix E is on the following four pages.

Research

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Publication date: 08-May-2003
Credit Analyst: Jeffrey Wolinsky, CFA, New York (1) 212-438-2117; Dimitri Nikas, New York (1) 212-438-7807; Anthony Flintoff, London (44) 20-7826-3874; Laurie Conheady, Melbourne (61) 3-9631-2036

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery--and thus release from the payment obligation--is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build--i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%--10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (11 plus 48). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Table 1 ABC Utility Co. Adjustment to Capital Structure				
	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	-	-	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2 ABC Utility Co. Adjustment to Pretax Interest Coverage					
		Original pretax interest coverage (x)		Adjusted pretax interest coverage (x)	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities canoffset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means.

Appendix F

	Position Regarding Debt Equivalence Adjustments
Louisiana	The Commission has not ruled on a debt equivalence adjustment for evaluating bids in an RFP process. However, the Commission staff has encouraged utilities to evaluate bids with and without a debt equivalence adjustment. Three RFP processes have been conducted under this method. For at least two of the RFPs, the application of a debt equivalence adjustment had no impact on the bid selection process. The third RFP is on-going and there is no formal information available at this time.
Oregon	The Oregon Commission recently issued an Order in UM 1182 (8/16/06). With regard to debt imputation, the Order stated that consideration of ratings agency debt imputation should be reserved for the selection of the final bids from the initial short-list of bids. The utility should obtain an advisory opinion from a ratings agency to substantiate its analysis and final decision, if requested by the Commission.

Utah	In its Report and Order in Docket NO. 03-035-14 on October 31, 2005 (QF Avoided Cost Case), the Utah Commission stated it was persuaded that based on the evidence in the case it was not clear how individual QF contracts may affect PacifiCorp's credit rating and therefore cost. There are 88 factors considered by Rating Agencies in the determination of a utility's credit rating. The Division Staff advocated using a 15% risk factor but the Commission instead focused on the Division's reference to the insufficient empirical evidence to support the debt equivalence hypothesis. PacifiCorp is again proposing to use a debt equivalence adjustment in evaluating bids submitted in response to the 2012 RFP for baseload supplies.
Florida	The Commission allows the utilities to include the cost of imputed debt to Bidder's proposals to assure that the total cost of proposals include the marginal impact of the fixed future commitments on the utility's capital structure. Florida Progress imputes a 30% risk factor in its assessment of bids through its RFP processes.
California	In its major December 2004 Decision on Power Procurement, the Commission allowed utilities to use a 20% risk factor in its bid evaluation process. The Commission also intends to address debt equivalence impacts in future cost of capital cases.
Washington	It is our understanding that the Commission allows the utilities to use a 15% risk factor in assessing the cost of imputed debt when comparing power purchase options.
Georgia	Georgia Power withdrew its request to apply a debt equivalence adjustment factor in the evaluation of bids in response to its 2009 RFP. However, the Commission staff

	in Georgia has continued to review this issue and determine if it is appropriate for application in future solicitations.
Connecticut	In Docket NO. 05-07-18 (December 28, 2005) the DPUC concluded that CL&P's proposal to roll debt equivalence charges into capacity contracts and the use of the debt equivalence adjustment in the evaluation and selection of bids are inappropriate. Should an electric distribution company's exposure to capacity contracts be shown to impact its financial condition, the Department will address the issue in a rate case.
Colorado	In Decision NO. C06-0657 in Docket NO. 05M-375E (April 5, 2006) the Commission denied a petition of PSCO to open a docket to consider revisions to the Commission's Least-Cost Resource Planning rules. The Commission disagreed with PSCO's proposal to address imputed debt in the least cost planning rules. The Commission stated that imputed debt should be generally addressed in a utility's rate case.